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Case No. PUE-2016-00143
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Bailiff: DEBORAH P. BELL

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COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION

APPLICATION OF

VIRGINIA NATURAL GAS, INC. CASE NO. PUE-2016-00143

For a general rate increase in rates and for authority to revise the terms and conditions applicable to natural gas service

DIRECT TESTIMONY OF

GLENN A. WATKINS

ON BEHALF OF

THE OFFICE OF THE ATTORNEY GENERAL

DIVISION OF CONSUMER COUNSEL

AUGUST 10, 2017

PUBLIC VERSION

EXHIBIT 17

VIRGINIA NATURAL GAS, INC.
CASE NO. PUE-2016-00143

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Summary of the Direct Testimony of Glenn A. Watkins

1. I have determined that VNG's jurisdictional cost of service study unreasonably over-assigns cost responsibility to SCC jurisdictional business. This is primarily due to two factors: (1) VNG assigns no cost responsibility to interruptible customers relating to transmission and distribution mains; and, (2) VNG has allocated and assigned distribution mains between jurisdictional and non-jurisdictional business partially on customer counts.

2. My jurisdictional cost study recommendation reduces the Company's requested overall jurisdictional revenue increase of $30.7 million to $16.0 million, accepting all other Company proposed accounting and ratemaking adjustments.

3. With regard to class cost of service, the Company has used methods similar to what it proposes for its jurisdictional cost operations. Similarly, I recommend the rejection of the Company's customer/demand split and recommend the Commission use the results of the Peak & Average and 7/12 methods as a guide in distributing any overall increase authorized in this case.

4. I disagree with the Company's proposed 82% increase to the monthly residential customer charge from $11.00 to $20.00 and recommend that this fixed monthly charge be maintained at the current $11.00 level.

VIRGINIA NATURAL GAS, INC.
CASE NO. PUE-2016-00143

DIRECT TESTIMONY OF
GLENN A. WATKINS

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SCHEDULES

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Glenn A. Watkins. My business address is 1503 Santa Rosa Road, Suite 130, Richmond, Virginia, 23229.

Q. WHAT IS YOUR PROFESSIONAL AND EDUCATIONAL BACKGROUND?

A. I am a Principal and Senior Economist with Technical Associates, Inc. ("TAI"), which is an economics and financial consulting firm with offices in Richmond, Virginia. Except for a six month period during 1987 in which I was employed by Old Dominion Electric Cooperative, as its forecasting and rate economist, I have been employed by Technical Associates continuously since 1980.

During my career at TAI, I have conducted marginal and embedded cost of service, rate design, cost of capital, revenue requirement, and load forecasting studies involving numerous electric, gas, water/wastewater, and telephone utilities. I have provided expert testimony on more than 200 occasions in Alabama, Arizona, Delaware, Georgia, Illinois, Indiana, Kansas, Kentucky, Maine, Maryland, Massachusetts, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Vermont, Virginia, South Carolina, Washington, and West Virginia.

I hold a M.B.A and B.S in economics from Virginia Commonwealth University and am a Certified Rate of Return Analyst. A more complete description of my education and experience as well as a list of my prior testimonies is provided in my Schedule GAW-1.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Over the last 30-plus years, I have testified before this Commission on dozens of occasions concerning virtually all aspects of public utility ratemaking.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. TAI has been engaged by the Office of the Attorney General, Division of Consumer Counsel ("OAG" or "Consumer Counsel") to evaluate Virginia Natural Gas Inc.'s ("VNG" or "Company") jurisdictional cost separations, class cost of service study ("CCOSS"), class revenue allocations, and proposed residential rate design as it relates to base distribution rates. The purpose of my testimony is to present the findings of my investigation and offer recommendations to the Commission in these areas.

II. JURISDICTIONAL COST ALLOCATIONS

Q. PLEASE EXPLAIN WHAT A JURISDICTIONAL COST STUDY IS AND HOW IT IS USED IN GENERAL RATE CASES.

A. More often than not, utilities operate under more than one regulatory jurisdiction. As its name implies, a jurisdictional cost study provides a basis to assign a utility's costs of providing service across its various regulatory jurisdictions; e.g., Federal (FERC), and/or multiple states. Additionally, the Virginia State Corporation Commission ("SCC") does not have jurisdiction over utility services provided to Federal, State, or local governmental customers located within the Commonwealth. Therefore, these governmental customers (located within Virginia's boundaries) must be treated as "non-jurisdictional." A jurisdictional cost of service study is nothing more than a cost allocation study in which a utility's total rate base, revenue and expense items (accounts) are assigned or allocated across various jurisdictions. These Virginia "jurisdictional" costs then serve as the basis for establishing the SCC jurisdictional revenue requirement, which in turn, is used by the SCC to develop specific rates. While some rate base investments and expense accounts can be directly attributable (assigned) to certain customers (such as a dedicated natural gas main), the majority of VNG's costs are incurred in a joint or common manner to serve all customers, and therefore, must be allocated across jurisdictions. As is the case with virtually all public utility cost studies, these allocations are based on one or more of the following three exogenous characteristics (allocators): peak (design) day demand, annual throughput (Dth), and number of customers.

Q. PLEASE EXPLAIN HOW VNG'S JURISDICTIONAL COST OF SERVICE STUDY IS STRUCTURED.

A. Unlike many, if not most, local distribution companies, VNG provides both intrastate transmission and distribution service. Therefore, in addition to typical distribution service, this Commission has jurisdiction over certain aspects of VNG's intrastate transmission service. In order to gain an understanding of the structure of VNG's jurisdictional cost study, a description of the geographical configuration of VNG's intrastate infrastructure is helpful.

VNG's jurisdictional business begins in Quantico, Virginia wherein a transmission line runs roughly parallel to Interstate 95 to Mechanicsville in Hanover

County. This transmission line is referred to as the Joint-Use Pipeline ("JUP"). Although VNG owns and operates the JUP to provide gas service to its ultimate retail distribution customers, it also provides transmission service to the following customers: the City of Richmond; Dominion Energy Virginia; Doswell Limited Partnership; and, Columbia Gas of Virginia.[1] These transmission customers contract for capacity on the JUP wherein they generally take delivery at or before Mechanicsville.[2] From Mechanicsville to North Hampton Roads, there is another VNG-owned pipeline referred to as the Lateral pipeline. In this regard, it should be understood that VNG provides retail distribution service (both jurisdictional and non-jurisdictional) in parts of Hanover, New Kent, and King William Counties.

At the termination of the Lateral Pipeline, VNG provides retail distribution service (both jurisdictional and non-jurisdictional) to North Hampton Roads. VNG's transmission system continues from the termination of the Lateral pipeline in North Hampton Roads under the James River with what is known as the HRX pipeline.[3] The HRX pipeline serves to supplement the distribution demands of VNG's distribution customers (both jurisdictional and non-jurisdictional) in Hampton Roads South of the

[1] While these JUP customers are serviced under contract rates approved by the Commission (Rate Schedule PT-1), in the most recent PT-1 rate case, in response to concerns raised by the Commission Staff, the Commission found that "any impact to the distribution ratepayers should be addressed in the Company's 2017 Base Rate Case that is currently pending before the Commission and in each base rate case filed thereafter." The Commission Staff had recommended that in approving Schedule PT-1, VNG's distribution ratepayers should be held harmless from any deficient returns produced by the PT-1 class. *Application of Virginia Natural Gas, Inc. For authority to revise Rate Schedule PT-1, Pipeline Transportation Service,* Case No. PUE-2016-00076, Final Order at 4, 5 (May 3, 2017).

[2] Columbia Gas of Virginia takes delivery at various points along the JUP as well as continuing to utilize **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** per day of pipeline capacity beyond the termination of the JUP in Mechanicsville.

[3] In the Company's jurisdictional cost study (Filing Schedule 40(b)), the HRX transmission line is separated into three components: Pipeline; Ladysmith; and, Charles City, where the latter two are compressor stations built to supply the required maximum capacity through the HRX.

James River.[4] A map of VNG's transmission system is provided in my Confidential Schedule GAW-2, which was provided in VNG's response to OAG Data Request 3-34.

Q. PLEASE CONTINUE WITH YOUR DESCRIPTION OF THE STRUCTURE OF VNG'S JURISDICTIONAL COST STUDY.

A. VNG has identified and separated transmission costs between the JUP, Lateral, and HRX pipelines. VNG's transmission service is referred to as "pipeline" within its jurisdictional cost study provided in Filing Schedule 40(b). VNG's total intrastate transmission (pipeline) operations consist of both jurisdictional and non-jurisdictional business, which is separated on page 2 of Filing Schedule 40(b). For the JUP, costs are first allocated to each entity utilizing this transmission line wherein VNG's total share of the JUP is 35.55%.[5] VNG's share of the JUP plus the Lateral and HRX transmission costs are then separated between jurisdictional and non-jurisdictional business based on design day demands.

With regard to distribution-related costs and with the exception of a small amount of direct assignments to transmission customers, these costs are referred to by VNG as "retail" business. This retail business also includes jurisdictional and non-jurisdictional business. For the largest component of distribution service; i.e., distribution mains, the Company classifies and allocates these costs partially on customers (43.6%) and partially on design day demands (56.4%). As a matter of arithmetic, VNG first allocates all costs

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[4] VNG's distribution system in South Hampton Roads is also supplied gas from non-affiliate transmission companies from the south.

[5] The City of Richmond, Dominion Energy Virginia, Doswell Limited Partnership, and Columbia Gas of Virginia collectively are assigned 64.45% of the JUP capacity and costs associated with the JUP.

to non-jurisdictional business (both pipeline and retail) and the residual (remaining) amount is considered jurisdictional business.

Q. IS VNG'S PROPOSED JURISDICTIONAL COST STUDY FAIR AND REASONABLE FOR SCC JURISDICTIONAL REVENUE REQUIREMENT PURPOSES?

A. No.

Q. PLEASE OUTLINE YOUR DISAGREEMENTS WITH VNG'S JURISDICTIONAL COST STUDY.

A. My examination of VNG's jurisdictional cost study has led me to conclude that the Company has significantly overstated the fair and reasonable costs associated with SCC jurisdictional business. In other words, VNG has over-allocated transmission and distribution costs to jurisdictional business and has under-allocated these same costs to non-jurisdictional business.

Q. PLEASE EXPLAIN THE BASIS FOR YOUR CONCLUSION THAT VNG HAS OVER-ASSIGNED COSTS TO SCC JURISDICTIONAL BUSINESS.

A. For purposes of this case, I have accepted VNG's assignment of costs between VNG "retail" business and "pipeline" business (primarily those transmission customers taking service on the JUP). As such, my disagreement with the Company's assignment of costs relates only to the separation of jurisdictional and non-jurisdictional business associated with its "retail" operations.[6] As indicated earlier, VNG has allocated transmission-related costs solely on the basis of design day demands and distribution mains-related costs based on a combination of number of customers and design day demands. Such an allocation results in a significant bias against jurisdictional ratepayers. This is because under the Company's as-filed jurisdictional study, no transmission or distribution mains-related costs are assigned to non-jurisdictional business, while the Company has significantly over assigned distribution-related costs to jurisdictional business based on their classification of distribution mains as partially customer-related and partially demand-related.

Even though VNG's interruptible customers use large amounts of natural gas throughout the year and depend on VNG's transmission lines to bring gas to their respective facilities, the Company assigns absolutely no transmission costs to these customers. The term of art used for this type of cost assignment is known as a "free ride." This is so because even though these (interruptible) customers may use VNG's transmission facilities throughout the year, they are able to utilize these facilities for free under VNG's allocation approach.

[6] As will be discussed later in my testimony, I recommend that jurisdictional allocations be based on the Peak & Average ("P&A") methodology. VNG was requested to conduct its jurisdictional study using the P&A approach in Staff Formal Data Request 2-18. In its response, the Company continued to allocate VNG's portion of the JUP based solely on contract demands with no consideration of throughput (average day demands) as specified in the P&A method. However, in reviewing VNG's assignment of JUP costs associated with its "VNG" business, I discovered two errors, that by and large, cancel each other out. As indicated earlier, VNG assigned 35.55% of JUP costs to its "Virginia" business while the remaining 64.45% is assigned to the other four contract transmission customers. In response to Confidential OAG Data Request 3-36, it was determined that VNG understates the "VNG" portion of JUP costs such that the correct amount should be 41.04%. However, when one recognizes the average component within the P&A approach, the Virginia portion of annual throughput (average day demand) is only 29.50%. Therefore, with the corrected peak portion of demand of 41.04% along with the average portion of 29.50%, a correct P&A allocation to Virginia business is 35.27%, which is almost identical to the 35.55% utilized by VNG in its as-filed jurisdictional study as well as in its P&A jurisdictional study.

VNG's assignment of distribution mains-related costs to jurisdictional and non-jurisdictional business is unreasonable for two reasons. First, and similar to its treatment of transmission-related costs, the Company has assigned no distribution mains costs to interruptible customers. Second, because there are few non-jurisdictional customers (primarily governmental) relative to the Company's jurisdictional retail business that includes about 275,000 residential customers, VNG's assignment of distribution mains-related costs over assigns cost responsibility to jurisdictional business.[7]

Q. DOES VNG ROUTINELY CURTAIL OR INTERRUPT RETAIL INTERRUPTIBLE CUSTOMERS (BOTH JURISDICTIONAL AND NON-JURISDICTIONAL)?

A. No. OAG Data Request 2-12(c) requested the following:

> With regard to VNG's retail interruptible customers and their respective usage, please provide: (c) an itemization of each interruption by customer showing the date, times, duration, estimated amount of each curtailment, and reason for interruption during the last five (5) years for each of the jurisdictional and non-jurisdictional customer(s) identified in (a).

VNG's response was:

> "interruptible customers were curtailed Thursday, February 19, 2015 at 12:00 a.m. lasting until Saturday, February 21, 2015 at 10:00 a.m. The interruption order was issued due to average daily temperatures being extremely low causing demand to be near design day levels."

As indicated from VNG's response, VNG has curtailed its interruptible customers due to capacity constraints only one time in at least the last five years. While Central and

[7] VNG's classification of distribution mains will be discussed and explained in much more detail in my discussion of class cost of service. However, it should be noted that VNG has used the same customer/demand split (43.6% customer/56.4% demand) in both its jurisdictional and class cost allocation studies.

Eastern Virginia did experience very cold weather on the curtailment date in 2015, the temperatures were not as low as during the Polar Vortex experienced during January 2013. Furthermore, in OAG Data Request 2-13, the Company was asked to provide the amount of curtailments on each annual system peak day during the last ten years (2009-2017). The Company responded that no interruptions occurred on annual peak days during the last ten years. As shown above, interruptible customers have been curtailed on only one occasion that lasted approximately 2.5 days during the last five years. To put this in perspective, over at least the last five years, VNG's jurisdictional and non-jurisdictional customers have enjoyed and utilized the VNG transmission and distribution system to meet their energy needs 99.9% of the time.[8]

At this point, it should be understood that if the relationship of VNG's interruptible and firm customers was the same between jurisdictional and non-jurisdictional business, this potential free-ride provision would be academic and moot. However, such is not the situation. To illustrate, the following is a comparison of relative interruptible and firm annual (Dth) throughput between jurisdictional and non-jurisdictional distribution customers.

[8] Over the last five years, interruptible customers were curtailed a total of approximately 2.5 days. Five years encompasses 1,825 days. Therefore, interruptible customers were curtailed 0.1% of the time. Conversely, they utilized the VNG system 99.9% of the time.

TABLE 1
Percent of Annual Throughput
(Distribution Customers)[9]

	Jurisdictional	Non-Jurisdictional
Interruptible	29.96%	38.12%
Firm	70.04%	61.88%
Total	100.00%	100.00%

As can be seen above, interruptible customers make up only about 30% of jurisdictional gas usage (throughput) but almost 40% of non-jurisdictional business.

Remembering that VNG does not allocate any transmission or distribution mains costs to interruptible customers such that they receive a free-ride under the Company's approach, it can be seen that its allocation of transmission and distribution costs results in a biased, unfair, and unreasonable assignment of costs to SCC jurisdictional business.

Q. MR. WATKINS, IS THERE A MORE FAIR AND REASONABLE METHOD TO ALLOCATE VNG'S TRANSMISSION AND DISTRIBUTION PLANT TO JURISDICTIONAL AND NON-JURISDICTIONAL BUSINESS?

A. Yes. Even though recognition should be given to the fact that non-firm service is of a lesser quality than firm service, interruptible customers should not be given an absolute free-ride. A fair and reasonable solution is to recognize both annual utilization of these facilities (throughput) as well as peak (design) day demand. This concept is known as the "Peak and Average" ("P&A") method and is widely used for natural gas costing studies. Under this approach, equal weight is given to peak (design) day and average day

[9] Test year jurisdictional interruptible throughput is 10,963,969 and total non-jurisdictional interruptible throughput is 2,523,455 (per response to OAG 2-12). Total system jurisdictional throughput is 36,595,270 and non-jurisdictional throughput is 6,619,067 (per response to Staff 1-2).

(throughput) characteristics such that interruptible customers are assigned no (zero) peak day responsibility but shares in its contribution to annual (average day) throughput. As may be apparent, this P&A method reflects a middle of the road approach in that interruptible customers are not assigned a full cost burden based on their annual usage, but also do not receive a free ride.

The P&A method produces a test year distribution non-jurisdictional allocation factor of 13.20% as compared to the design day factor utilized by VNG of 11.08%. A table of test year design day, throughput, and P&A allocators is provided below illustrating the resulting reasonableness of the P&A method in this application:

TABLE 2

Distribution Allocation	Jurisdictional	Non-Jurisdictional
Design Day	88.92%	11.08%
Throughput	84.68%	15.32%
Peak & Average	86.80%	13.20%

Q. **WAS VNG REQUESTED TO PERFORM ITS JURISDICTIONAL COST ALLOCATION STUDY UTILIZING ALTERNATIVE ALLOCATION APPROACHES?**

A. Yes. In Staff Data Request 2-18, the Company was requested to provide its jurisdictional cost of service study under two alternative allocation methodologies: one using the seven-twelfths; and, another utilizing the P&A. The Company complied with this request and provided these studies in electronic format.

Q. YOU HAVE ALREADY DISCUSSED THE P&A METHOD. PLEASE DESCRIBE AND EXPLAIN THE SEVEN-TWELFTHS METHOD.

A. The seven-twelfths ("7/12") approach to allocate mains-related costs is similar in concept to the P&A method in that it also assigns some cost responsibility to interruptible customers. It therefore avoids the free ride problem associated with the Peak Responsibility method that only considers design day demands. Like the P&A, the seven-twelfths method recognizes that interruptible service is of a lesser quality than firm service, and therefore does not assign the same level of costs to interruptible service as is assigned to firm service. The seven-twelfths method utilizes 7/12 of interruptible throughput as a surrogate for the demand responsibility associated with this type of service. The theory behind the seven-twelfths approach is that interruptible customers tend to have a high load factor and that only their imputed throughput during the non-heating months (7 months) is considered within the demand responsibility such that usage during the heating season is not considered as it would have the potential for interruption.

Q. WHAT IS YOUR OPINION REGARDING THE REASONABLENESS OF THE SEVEN-TWELFTHS METHOD?

A. While the seven-twelfths approach is superior to the Peak Responsibility only method, it is rarely used for cost allocation purposes in the natural gas industry. Indeed, the P&A method is much more commonly used. This being said, I will not criticize the seven-twelfths approach as necessarily being inferior to the P&A approach as both prevent a free ride for interruptible customers and both approaches assign fewer costs to interruptible business than firm service; i.e., do not treat interruptible service as if it were firm.

Q. FOR PURPOSES OF THIS CASE, WHAT METHOD DO YOU RECOMMEND THE COMMISSION RELY UPON IN ESTABLISHING THE SCC JURISDICTIONAL REVENUE REQUIREMENT?

A. I recommend the Commission rely on the P&A method to develop the jurisdictional revenue requirement in this case. This is so because the P&A method is more commonly used in the industry, and to be conservative, the P&A method produces a somewhat higher jurisdictional revenue requirement than the seven-twelfths method.

Q. PLEASE PROVIDE A SUMMARY OF THE COMPANY'S JURISDICTIONAL COST OF SERVICE STUDY RESULTS UNDER THE COMPANY'S APPROACH, THE SEVEN-TWELFTHS METHOD, AND THE P&A METHOD THAT YOU ALLOCATE.

A. The following table provides a summary of test year allocated jurisdictional amounts under each of the three methods:

TABLE 3
Summary of Jurisdictional Cost Allocation Results
($000)

	VNG Proposed	7/12 Method	P&A Approach
Non-Gas O&M	$57,559	$55,723	$55,828
Purchased Gas	$70,534	$70,534	$70,534
Depreciation Expense	$29,222	$28,278	$28,342
Taxes Other Than Income	$7,978	$7,749	$7,764
Income Taxes	$19,336	$20,796	$20,706
Total Expenses	$184,629	$183,080	$183,175
Plant in Service + CWIP	$1,182,847	$1,145,276	$1,147,921
Depreciation Reserve	-$365,316	-$353,435	-$354,260
Other Rate Base Items	-$186,446	-$181,303	-$182,095
Total Rate Base	$631,085	$610,538	$611,566

Q. NOTWITHSTANDING YOUR DISAGREEMENT WITH VNG IN THAT SOME COST RESPONSIBILITY SHOULD BE ASSIGNED TO INTERRUPTIBLE CUSTOMERS, DO YOU HAVE ANY DISAGREEMENTS WITH THE COMPANY'S JURISDICTIONAL COST STUDY?

A. Yes. I have reviewed VNG witness Heintz's selected allocators for every rate base and operating income account. As a result of this review, I have only one significant disagreement with Mr. Heintz's selection of allocation factors for individual accounts. This disagreement relates to his selected allocator to assign costs to Distribution Land & Land Rights (Account 374) and Distribution Structures & Improvements (Account 375). Mr. Heintz allocated these two rate base accounts to jurisdictional and non-jurisdictional business based on number of customers. However, VNG's investment in land, land rights, and structures and improvements is more properly related to its investment in distribution mains as these investments are directly attributable to distribution mains and should follow the allocation method to allocate distribution mains. Mr. Heintz's allocation of these two accounts based on number of customers results in another bias against jurisdictional business in that it assigns more cost responsibility to the jurisdictional revenue requirement than is appropriate. To illustrate, the jurisdictional customer's allocation factor is 98.98% while the jurisdictional mains costs responsibility is significantly less under any of the distribution mains allocation methodologies noted earlier.[10] My recommended jurisdictional allocation study results are presented in my Schedule GAW-3.

Q. WHAT IS THE IMPACT OF ALLOCATING THESE TWO DISTRIBUTION RATE BASE ACCOUNTS BASED ON MAINS RATHER THAN NUMBER OF CUSTOMERS?

A. Utilizing the P&A method to allocate mains, the following is a comparison of the Company's P&A study (provided in response to Staff Data Request 2-18) in which these two accounts are allocated on the number of customers to the same model except that these accounts are allocated based on distribution mains investment:

[10] The jurisdictional distribution mains allocation factors under the three approaches are as follows:

VNG Proposed Customer/Demand Method	93.31%
Seven-Twelfths Method	86.42%
P&A Method	86.80%

TABLE 4
Comparison of Jurisdictional P&A Results
Distribution Accounts 374 and 375
Allocated on Customers vs. Distribution Mains

	VNG Allocation on Customers	Allocation on Distribution Mains
Non-Gas O&M	$55,828	$55,817
Purchased Gas	$70,534	$70,534
Depreciation Expense	$28,342	$28,287
Taxes Other Than Income	$7,764	$7,754
Income Taxes	$20,706	$20,754
Total Expenses	$183,175	$183,146
Plant in Service + CWIP	$1,147,921	$1,145,816
Depreciation Reserve	-$354,260	-$353,572
Other Rate Base Items	-$182,095	-$182,047
Total Rate Base	$611,566	$610,197

Given the Company's requested cost of capital, the jurisdictional revenue requirement impact on these differences is in the neighborhood of $170,000.

Q. HAVE YOU CALCULATED THE REVENUE REQUIREMENT IMPACT OF UTILIZING YOUR RECOMMENDED JURISDICTIONAL COST OF SERVICE STUDY AS COMPARED TO THE JURISDICTIONAL COST STUDY VNG PROPOSES IN THIS CASE?

A. Yes. The Company's proposed rate year (ending August 31, 2018) jurisdictional revenue requirement is provided in Filing Schedule 21. In developing Filing Schedule 21, the Company begins with the results of the jurisdictional cost of service study based on test year ending September 30, 2016. Next, the second column of Filing Schedule 21 reflects various proposed ratemaking adjustments that in large part, bring historic test year amounts forward to the rate year ending August 31, 2018. In calculating VNG's proposed ratemaking adjustments, the Company first estimated total Company (jurisdictional plus non-jurisdictional) amounts and then applied appropriate jurisdictional allocation factors to these projected total Company amounts. The Company's ratemaking adjustments are provided in Schedule 25 through 28 of the Filing Requirements. I was provided an electronic version of the Company's revenue requirement filing schedules wherein I was able to utilize the methodology employed by VNG in developing its proposed revenue requirements but substituting my recommended jurisdictional allocation factors to each proposed adjustment. As a result, I was able to develop VNG's jurisdictional revenue requirement utilizing all of its proposed accounting and ratemaking adjustments (including its requested rate of return on rate base) by substituting my various jurisdictional allocation factors.

VNG is requesting an increase in its jurisdictional revenues of $30.702 million. By utilizing my recommended jurisdictional allocation factors, and accepting all other aspects of VNG's request, this requested increase is reduced by $14.741 million to $15.961 million. The development of the $15.961 million jurisdictional revenue requirement utilizing my jurisdictional allocation factors is provided in my Schedule GAW-4, which utilizes the same format as the Company's Filing Schedules 21 through 28.

Q. AS TO VNG'S PROPOSED EXCLUSION OF MAINS PLANT AND RELATED COST RESPONSIBILITY, HAS THIS COMMISSION PROVIDED GUIDANCE ON THIS ISSUE IN PREVIOUS VNG RATE CASES?

A. Yes. In VNG's 2005 rate case (Case No. PUE-2005-00062), VNG also proposed to exclude mains-related cost assignment relating to its interruptible service. The issue of whether cost should or should not be allocated to interruptible classes was fully explored by VNG, Consumer Counsel, the industrial intervenors, and Staff. In that case, the Hearing Examiner made the following recommendation:

> Based on the record, I find that VNG's class cost of service study should continue to assign fixed costs to interruptible customers and that VNG's proposed margin sharing adjustment should be denied. I agree with Staff that the Second Stipulation and the contingencies related to the retention of interruptible customers demonstrate that a portion of the cost of the distribution system should be borne by interruptible customers. Furthermore, I agree with VIGUA that without separate inclusion of interruptible classes in the class cost of service study, there is no meaningful way to determine if the rates charged such customers are just and reasonable.[11]

In its final order in that case, the Commission adopted this recommendation of the Hearing Examiner.[12] While the above findings relate to class cost of service, the concept is identical for jurisdictional cost separations.

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[11] *General Rate Case Filing of Virginia Natural Gas, Inc. For investigation of justness and reasonableness of current rates, charges, and terms and conditions of service in compliance with prior Commission Order*, Case No. PUE-2005-00062, Report of Alexander F. Skirpan at 57 (May 18, 2006).

[12] *General Rate Case Filing of Virginia Natural Gas, Inc. For investigation of justness and reasonableness of current rates, charges, and terms and conditions of service in compliance with prior Commission Order*, Case No. PUE-2005-00062, Final Order at 9 (July 24, 2006).

III. CLASS COST OF SERVICE

Q. PLEASE EXPLAIN THE CONCEPT OF A CLASS COST OF SERVICE STUDY ("CCOSS").

A. There are two general types of cost of service studies used for public utility ratemaking: marginal cost studies and embedded, fully allocated cost studies. VNG has utilized a traditional embedded cost of service concept in this case for purposes of establishing its overall retail revenue requirement, as well as for its CCOSS. Embedded cost of service studies are often referred to as fully allocated cost studies. Because the majority of a public utility's plant investment and expense are incurred to serve all customers in a joint manner, most costs cannot be specifically attributed to any individual customer or group of customers. Therefore, the costs jointly incurred to serve all or most customers must be allocated across specific customers or customer rate classes. To the extent that certain costs can be specifically attributed to a particular customer (or group of customers), these costs are directly assigned in a CCOSS.

It is generally accepted that to the extent possible, joint costs should be allocated to customer classes based on the concept of cost causation. That is, costs are allocated to customer classes based on analyses that measure the causes of the incurrence of costs to the utility. Although the cost analyst strives to abide by this concept to the greatest extent practical, some categories of costs, such as corporate overhead costs, cannot be attributed to specific exogenous measures or factors, and must be subjectively assigned or allocated to customer rate classes. For those costs to which causation can be attributed, there is often disagreement among cost of service experts on what is an appropriate cost causation measure or factor; e.g., peak demand, energy or throughput usage, number of customers, etc.

Q. IN YOUR OPINION, HOW SHOULD THE RESULTS OF A CCOSS BE UTILIZED IN THE RATEMAKING PROCESS?

A. Although certain principles are used by all cost of service analysts, there are often significant disagreements on the specific factors that drive individual costs. These disagreements can and do arise as a result of the quality of data and level of detail available from financial records. There are also fundamental differences in opinions regarding the cost causation factors that should be considered to properly allocate costs to rate schedules or customer classes. Furthermore, and as mentioned previously, cost causation factors cannot be realistically ascribed to some costs such that subjective decisions are required.

In these regards, two different cost studies conducted for the same utility and time period can, and often do, yield different results. As such, regulators should consider CCOSS only as a guide, with the results being used as one of many tools to assign class revenue responsibility.

Q. HAVE THE COURTS OPINED ON THE USEFULNESS OF COST ALLOCATIONS FOR PURPOSES OF ESTABLISHING REVENUE RESPONSIBILITY AND RATES?

17082188

A. Yes. In an important regulatory case involving Colorado Interstate Gas Company and the Federal Power Commission (predecessor to the Federal Energy Regulatory Commission ("FERC")), the United States Supreme Court stated:

> But where as here several classes of services have a common use of the same property, difficulties of separation are obvious. Allocation of costs is not a matter for the slide-rule. It involves judgment on a myriad of facts. It has no claim to an exact science.[13]

Q. DOES YOUR OPINION, AND THE FINDINGS OF THE U.S. SUPREME COURT, IMPLY THAT COST ALLOCATIONS SHOULD PLAY NO ROLE IN THE RATEMAKING PROCESS?

A. Not at all. It simply means that regulators should consider the fact that cost allocation results are not surgically precise and that alternative, yet equally defensible, approaches may produce significantly different results. In this regard, when all cost allocation approaches consistently show that certain classes are over- or under-contributing to costs and/or profits, there is a strong rationale for assigning smaller or greater percentage rate increases to these classes. On the other hand, if one cost allocation approach shows dramatically different results than another approach, caution should be exercised in assigning disproportionately larger or smaller percentage increases to the classes in question.

Q. PLEASE EXPLAIN THE BASIC CONCEPTS OF COST ALLOCATION FOR PUBLIC UTILITIES AND NATURAL GAS DISTRIBUTION COMPANIES ("NGDCs").

[13] *Colorado Interstate Gas Co. v. Federal Power Commission,* 324 U.S. 581, 590 (1945).

A. As I mentioned earlier, the majority of a NGDC's plant investment serves customers in a joint manner. In this regard, the NGDC's infrastructure is a system benefiting all customers. If all customers were the same size and had identical usage characteristics, cost allocation would be simple (even unnecessary). However, in reality, a utility's customer base is not so simple. There are small usage customers and large usage customers and these customers (or customer groups) tend to vary greatly in the amount of service required throughout the year. Therefore, differences in usage should be considered. Because different groups of customers also utilize the system at varying degrees during the year, consideration should also be given to the demands placed on the system during peak usage periods.

Q. FOR NGDCs, IS THERE ANY ASPECT OF CLASS COST ALLOCATIONS THAT TENDS TO OVERSHADOW OTHER ISSUES OR IS OFTEN CONTROVERSIAL?

A. Yes. For virtually every NGDC, the largest single rate base item (account) is distribution mains. Furthermore, several other rate base and operating income accounts are typically allocated to classes based on the previous assignment of distribution mains. As such, the methods and approaches used to allocate distribution mains to classes are usually by far the most important (in terms of class ROR results) and tend to be the most controversial.

Q. BEFORE YOU DISCUSS THE VARIOUS METHODS AND APPROACHES USED TO ALLOCATE MAINS, ARE THERE ANY MEASUREMENT CONCEPTS THAT ARE CRITICAL TO FULLY UNDERSTAND?

A. Yes. Most public utility costing studies consider some form of peak demand. For NGDCs, peak demand is usually expressed on a peak day basis. However, there are several concepts and definitions relating to peak day demand that should clearly be understood. The first set of concepts and definitions concern actual and potential (theoretical) peak day demands. Actual peak day demands are just that: the actual maximum demands measured (or estimated) over some pre-defined period; e.g., a test year. Potential, or theoretical, peak day demands are referred to as "design day" demands and reflect the estimated demands on the coldest day realistically possible for a particular geographic service area.[14]

The next set of definitional "peak day demands" relate to the timing, or "coincidence" of demands, between various user groups or classes. Class coincident peak demands are defined as class usage on the day of the system peak (whether on an actual or design day basis). Class non-coincident peak ("NCP") day demands relate to each class's peak day usage, regardless of when the entire system peaks. Because of the highly weather sensitive nature of NGDC systems, class coincident and NCP day demands are usually on the same day for the residential and commercial classes. For some NGDCs, the industrial NCP day demand may not coincide with the system (coincident) peak day usage depending on scheduling and production outputs of these industrial customers.

Q. WHAT METHODS ARE COMMONLY USED TO ALLOCATE NATURAL GAS DISTRIBUTION MAINS?

[14] Residential and commercial natural gas usage tends to be extremely weather sensitive, while industrial usage may or may not be weather sensitive depending on the use of gas by these customers for space heating and industrial processes.

A. While a myriad of cost allocation methods and approaches have been developed, three methods predominate in the NGDC industry: peak responsibility, Peak and Average, and Customer/Demand, which I will address shortly in more detail. These methods differ in the criteria used to allocate mains, as cost allocation analysts do not universally agree on the cost causative factors or drivers influencing mains investments. There are three criteria generally considered when selecting a mains cost allocation method: peak demand (whether coincident, non-coincident, actual or design day); annual (average day) usage; and, number of customers. Because a NGDC system must be capable of supplying gas to its firm customers during peak demand periods (i.e., on very cold days), relative class peak day demands are often considered a good proxy for measuring the cost causation of mains investment.[15] Annual (or average day) throughput is also often used to allocate mains as this factor reflects the utilization of a utility's mains investment. Number of customers is also sometimes considered when allocating mains. That is, customer counts by class serve as a basis for allocation of mains. Even though annual levels of usage and peak load requirements vary greatly between customer classes (residential versus large industrial), some analysts are of the opinion that customer counts should be considered because at least some infrastructure investment in mains is required simply to "connect" every customer to the system. With these three criteria identified, various methods weight and utilize these criteria differently within the cost allocation process. In other words, some methods rely on only one criterion while others consider two or more criteria with varying weights given to each factor utilized.

[15] Embedded cost allocations are only concerned with relative, not absolute, criteria. That is, because embedded cost allocations reflect nothing more than dividing total system costs between classes, it is the relative (percentage) contributors to total system amounts that are relevant.

The three most common NGDC cost allocation methods are: the peak responsibility method (whether coincident or class non-coincident) in which peak day demands are the only factor utilized to allocate mains; the Peak and Average approach in which both peak day and annual (average day) throughput is reflected within the allocation of mains;[16] and the Customer/Demand method that utilizes a combination of peak day demands and customer counts to assign mains cost responsibility.

Under the Customer/Demand method, the weights given to class customer counts and peak day demands are determined from a separate analysis using one of two approaches: minimum-size and zero-intercept. The "minimum-size" approach prices the entire system footage of mains at the cost per foot of the smallest diameter pipe installed. This "minimum-size" cost is then divided by the actual total investment in mains to determine the weight given to customer counts. One (1) minus the customer percentage is then given to the peak day demand within the allocation process. The second approach used to classify and allocate mains based partially on customers and partially on peak demand is known as the "zero-intercept" method. Under this approach, statistical linear regression techniques are used to estimate the cost of a theoretical "zero size" main. Similar to the minimum size approach, the cost of this estimated zero size pipe per foot is multiplied by the total system footage and is then divided by total mains investment to arrive at a customer weighting.

[16] Under the Peak and Average approach, peak use and annual throughput are either weighted equally or based on system load factor, where load factor is ratio of average daily usage to peak day usage. When using a load factor approach to weight Peak and Average usage, the weighting of average day usage is that of the system load factor while the peak day weight is one minus the system load factor.

Q. IN YOUR OPINION, IS THERE A PREFERRED METHOD TO ALLOCATE NATURAL GAS DISTRIBUTION MAINS COSTS?

A. Yes. In my opinion, the P&A approach is the most fair and equitable method to assign natural gas distribution mains costs to the various customer classes. This method recognizes each class's utilization of the Company's facilities throughout the year yet also recognizes that some classes rely upon the Company's facilities (mains) more than others during peak periods.

Q. EARLIER YOU INDICATED THAT SOME ANALYSTS PREFER TO EMPLOY THE PEAK RESPONSIBILITY METHOD IN WHICH MAINS ARE ALLOCATED SOLELY ON THE BASIS OF PEAK LOADS. IN YOUR OPINION, WHY IS THIS METHOD GENERALLY INFERIOR TO THE P&A METHOD TO ALLOCATE MAINS?

A. While it is appropriate to consider and reflect class peak demands when allocating distribution mains, it should not be the only criteria. A NGDC system is constructed and is in existence in order to serve the natural gas energy needs of its customers throughout the year. If VNG's (or any NGDC's) customers only demand gas for one day of the year (the so-called peak day), the costs to deliver gas throughout the system would be prohibitively high such that a system would never exist. In other words, VNG's customers' demand and utilize natural gas every day of the year, not just one day out of 365 days. If by chance, a customer did require gas for only one day a year, it would be prohibitively expensive to the Company (and ultimately the customer) to provide service as the investment in mains would therefore be required to be recovered from a very small amount of natural gas energy (usage) and would be economically unfeasible.

Furthermore, there is not a direct relationship between peak loads (capacity requirements) and the cost incurred to install mains. For example, if the peak load on one line segment of mains is double that of another line segment, the cost of mains for the higher capacity pipe may be higher but is not double that of the lower capacity. This reality reflects the major shortcoming of the Peak Responsibility method (which allocates mains entirely on peak day demand), which is that it is premised on the incorrect assumption that there is a direct and perfectly linear relationship between peak loads, system capacity, and costs. Regarding system capacity, the amount of gas that can be delivered throughout a NGDC system is not only a function of the size of pipe(s) but also pressurization of gas within these pipes, and, as well, the presence or absence of looping various segments of the distribution system. In very simple terms, and all else constant, the *capacity* of pipes increase by a factor of exactly 4 to 1 as the *diameter* of pipe increases.[17] Therefore, if the size of pipe is doubled, the capacity of the pipe increases by a factor of four. At the same time, the cost of this additional capacity is far less than four times as much.[18]

Additionally, and as important as the geometric capacity of pipe at a given pressure, the amount of gas (measured in cubic feet) required to be pushed through a

[17] The volume of a cylinder (pipe) is equal to pi (3.14159) x Radius^2 x length. Therefore, it can be seen that as the diameter doubles, the area (volume) of the pipe increases by four times that of the smaller pipe.

[18] The cost of mains investment reflects the cost of capitalized labor to install the Main plus the cost of materials (the piping). Although the labor cost of installing pipe increases somewhat with larger size pipe, these additional labor costs tend to be much smaller than the capacity added. Similarly, the materials cost of the pipe also increases but by a much smaller percentage than the capacity added.

distribution system can be met with larger pipes at lower pressures or smaller pipes at higher pressures. With increases in materials, technology, and pipe coupling improvements, we are seeing that NGDCs are expanding and replacing their systems with *smaller* plastic pipes operated at *higher* pressures. Because the allocation of mains only concerns the assignment of the pipes costs, there is not a clear relationship between a main segment's capacity (peak load ability) and the cost of that pipe. The relevance of this is that an allocation method that only considers peak load by definition assumes there is a direct and perfectly linear relationship between load (capacity) and the cost of mains. This assumption is clearly not accurate.

Finally, and perhaps most important, is the fact that class contributions to peak loads are typically estimates at best. Unlike the electric utility industry in which load studies are typically conducted based on a sampling of customers with demand recording meters actually installed, NGDCs rarely conduct such load studies. While some large industrial customer's peak day demands are known with reasonable certainty due to the installation of demand meters, residential, commercial, municipal and small to medium sized industrial customers typically only have volumetric meters. As a result, most NGDCs estimate the majority of class contributions to peak day load by simply subtracting large industrial peak day demands from system peak day demands (which is known as a result of deliveries to city gates) and then somehow allocating the remainder to the residential, commercial, municipal and small to medium sized industrial classes. As will be discussed later in this testimony, this can lead to significant uncertainty as it relates to the estimates of individual class contributions to peak demand. In other words, due to the top-down allocation approach often utilized to estimate class peak demands, one class' estimate may be significantly overstated while another class may be significantly understated.

Q. THE THIRD ALLOCATION METHOD YOU MENTIONED EARLIER ALLOCATES MAINS PARTIALLY ON SOME MEASURE OF PEAK DEMAND AND PARTIALLY ON NUMBER OF CUSTOMERS. WHAT RATIONALE IS USED TO ALLOCATE MAINS INVESTMENT, AT LEAST PARTIALLY, BASED ON CUSTOMER COUNTS?

A. I am aware of two rationales, or arguments, used to advocate the allocation of natural gas distribution mains based partially on number of customers.

The first rationale used by some analysts is that, because every customer (regardless of size) must be physically connected to the utility's distribution network, there is some minimum level of investment required to simply connect customers to the distribution system. It is certainly true that, unless natural gas is delivered in a portable tank or cylinder, some form of a physical "plumbing" is required to deliver natural gas to each and every end-user.[19] Indeed, this is the very purpose of the distribution system. However, no customer connects to a NGDC system simply to be connected but never utilize natural gas, nor do NGDCs haphazardly install natural gas mains where no usage is present or anticipated. Because there is no economic utility (benefit) derived from simply being connected to a system, there is no economic (or cost causative) basis for assigning some value of a NGDC's distribution mains required to simply connect customers.

[19] If natural gas was delivered to end-users in tanks (such as done with propane), there would be no distribution system, or mains to allocate.

The second rationale used to consider number of customers within the allocation of mains relates to customer densities and differences in the mix of customers (by class) throughout a utility's service area. Possibly the best way to explain why customer densities may be relevant in the assignment of distribution costs to individual classes is by way of example. Consider two different utilities: a rural electric utility with urban, suburban, and rural service areas and another utility with only urban and suburban customers. With respect to the electric utility with a rural service area, many miles of conductors and associated plant must be installed in order to serve the demands of relatively few customers. Conversely, many more customers are served on a per mile basis for the urban/suburban utility. With respect to the utility with a rural service area, such an allocation based on usage or demand may be unfair if some classes are located mainly in urban or suburban areas, while other classes of customers are located in urban, suburban, and rural areas. As a result, some cost studies classify distribution plant as partially demand-related and partially customer-related.

While these conceptual arguments have no economic or practical logic in my opinion, the second rationale may produce reasonable results in some instances, but is rarely applicable to NGDC's.

Q. IN THE ABOVE EXAMPLE, YOU REFERRED TO ELECTRIC UTILITIES INSTEAD OF NATURAL GAS UTILITIES. IS THERE A REASON WHY YOU SELECTED THE ELECTRIC UTILITY INDUSTRY FOR YOUR EXAMPLE?

A. Yes. Although the concepts are the same between electric and natural gas distribution facilities (e.g., conductors are synonymous with mains), electric utilities are *required* to serve rural (sparsely populated) areas. Such requirements, however, are *not* in place for NGDCs. Moreover, electric utilities are required to connect all consumers regardless of density or usage. Such is not the case for NGDCs, as their tariffs allow the utility to only connect those customers in areas with sufficient customer densities and usage.

As such, and as a general matter, a Customer/Demand classification of *electric* distribution facilities may be appropriate given the characteristics of a utility's service area, but are rarely appropriate for NGDCs with more densely populated service areas that are not required to serve all potential residences and businesses.

Q. HAVE YOU EXAMINED THE CCOSS CONDUCTED BY VNG WITNESS HEINTZ IN THIS CASE?

A. Yes. The methods and approaches used by Mr. Heintz for CCOSS purposes largely mirror those that he used for his jurisdictional cost of service study. Of particular importance is his allocation of distribution mains investment wherein he used the Customer/Demand approach and has classified and allocated these related costs based on 43.60% on customer counts and 56.40% on design day demands. In this regard, it is also important to understand that Mr. Heintz has assigned no distribution mains cost responsibility to interruptible customers. Furthermore, and consistent with his jurisdictional study, Mr. Heintz has allocated Distribution Land & Land Rights (Account 374) and Distribution Structures & Improvements (Account 375) based on number of customers.

Q. WITH REGARD TO MR. HEINTZ ALLOCATING DISTRIBUTION MAINS-RELATED COSTS BASED PARTIALLY ON NUMBER OF CUSTOMERS AND PARTIALLY ON PEAK DEMAND, WHAT RATIONALE DOES HE PROVIDE FOR ALLOCATING THESE COSTS BASED PARTIALLY ON CUSTOMERS AND PARTIALLY ON PEAK DEMAND?

A. On page 9 of his direct testimony, Mr. Heintz sets forth his rationale for allocating distribution mains partially on number of customers and partially on peak demand. Mr. Heintz's rationale is as follows:

> It is widely accepted that distribution mains are installed both to meet system peak load requirements and to connect customers to the Company's system. There are two cost factors that influence the amount of distribution main investment installed by a company in expanding its gas distribution system: the size of the main (pipe diameter) and the total footage. The size of the main is directly influenced by the sum of the peak period gas demands of the system customers. *The total installed footage of distribution mains is influenced by the need to expand the distribution grid to connect new customers to the system. Therefore, to ensure that the rate classes that cause the incurrence of this plant investment or expense are charged with its cost, distribution mains should be allocated to the rate classes on both the basis of peak load requirements and the number of customers within each of the classes of service.* [Emphasis added]

Q. NOTWITHSTANDING THE CONCEPTUAL REASONS WHY IT IS NOT APPROPRIATE TO ALLOCATE A PORTION OF NATURAL GAS DISTRIBUTION MAINS BASED ON NUMBER OF CUSTOMERS AS A GENERAL MATTER, IS MR. HEINTZ'S RATIONALE AND SUPPORT FOR ALLOCATING A PORTION OF DISTRIBUTION MAINS BASED ON NUMBER OF CUSTOMERS CONSISTENT WITH VNG'S ACTUAL PRACTICES OR ITS COMMISSION APPROVED TARIFF?

A. No. As noted earlier, NGDCs do not haphazardly install natural gas mains where no usage or revenue is present or anticipated; i.e., they do not install mains simply to connect customers. VNG's actual practices and tariff are fully consistent with this observation. Section XVIII (Gas Line Extensions) of the Company's tariff states as follows:

> The Company will make gas line extensions to such points as will provide sufficient continuing revenue to justify such line extensions, or in lieu of sufficient continuing revenue, the Company may require such definite and written guarantees from a Customer, or group of Customers, in addition to any minimum payments required by the rate schedules as may be necessary to justify such line extensions. The Company shall not be obligated to construct or own any gas line extension or other facilities to provide any Customer with gas, the cost of which shall exceed 5.7 times the continuing annual revenue excluding the cost of gas, that can reasonably be expected by the Company from any such line extensions. However, if the Company provides any such line extensions, the Customer shall pay to the Company any cost exceeding 5.7 times the annual revenue as defined above, multiplied by a tax recovery factor.

As indicated above, the Company's line extension policy is clear in that the Company only connects and serves those customers that have enough usage and revenue to justify the Company's investment in its infrastructure.

Q. SO THAT IT IS CLEAR, WHAT IS THE CORRELATION BETWEEN CUSTOMER DENSITIES AND VNG'S LINE EXTENSION POLICIES AND TARIFF WITH WHETHER DISTRIBUTION MAINS SHOULD BE ALLOCATED PARTIALLY ON THE BASIS OF NUMBER OF CUSTOMERS?

A. The fundamental concept of embedded cost allocations is the principle of cost causation. For distribution mains, it is clear that VNG's distribution system is not designed, installed, or operated, simply to connect customers. Rather, distribution mains are designed, installed, and operated *only* if there is enough usage to justify the investment.

While these mains must be sized and pressurized in a sufficient manner to provide customers with natural gas even on peak days, there is no question that the number of customers has anything to do with the design, installation, or operation of the Company's distribution system.[20]

Q. NOTWITHSTANDING YOUR OPINION THAT VNG'S DISTRIBUTION MAINS SHOULD NOT CONSIDER OR ALLOCATE THESE COSTS BASED ON NUMBER OF CUSTOMERS, HAVE YOU EVALUATED MR. HEINTZ'S STUDY IN WHICH HE HAS CLASSIFIED AND ALLOCATED DISTRIBUTION MAINS AS 43.60% CUSTOMER AND 56.40% DEMAND?

A. Yes. In doing so, I discovered a number of conceptual and data errors within his analysis. These errors are of such magnitude that his conclusions and recommendation should be disregarded.

Q. PLEASE EXPLAIN THE CONCEPTUAL ERRORS IN MR. HEINTZ'S CUSTOMER/DEMAND ANALYSIS.

A. As mentioned earlier, there are two generally accepted approaches to classify distribution mains between customer and demand when such a classification is appropriate. Mr. Heintz has utilized a variant of the Minimum-Size or Minimum-System method. Under the Minimum-System method, the cost of a "minimum-sized" pipe per foot is utilized as the basis for the customer component. This cost of a minimum-sized pipe is then

[20] It is recognized that there are distribution costs that are considered customer-related. In particular, these include service lines and meters. In this regard, these costs are properly allocated based on a weighted customer basis wherein the costs are generally recovered from fixed monthly customer charges and/or contributions in aid of construction ("CIAC").

multiplied by the total mains footage of the distribution system to serve as the numerator in an equation. The denominator of the equation is the total cost of the system (that includes all sizes of pipes). The resulting quotient is then the customer component.

When conducting a Minimum-Size study, recognition must be given to the fact that even the minimum sized pipe actually installed has a significant load carrying capability and therefore, actually serves the maximum peak demands of at least some customers. In these regards, Mr. Heintz has selected a 2-inch plastic pipe as his "minimum size." Even though a 2-inch plastic pipe is not the actual minimum size main within the VNG system, 2-inch plastic mains are the predominant main size serving residential customers. These 2-inch mains are of sufficient capacity to serve these customers throughout the year and to meet their design day demands. Therefore, and by definition, Mr. Heintz has significantly overstated the customer component simply because 2-inch mains are sized to meet these customers' peak demands. As a matter of arithmetic, Mr. Heintz's approach results in a significant bias against residential customers in that there is a double count, or double assignment, of mains costs to the residential class. This is because Mr. Heintz allocates these 2-inch mains based on number of customers in which the vast majority of VNG's customer mix are residences and then again allocates costs to the residential class based on their peak (design) day demand (which is largely served by 2-inch plastic mains).

Q. PLEASE EXPLAIN THE DATA ERRORS IN MR. HEINTZ'S CUSTOMER/DEMAND ANALYSIS.

A. Mr. Heintz provided his workpapers used to develop his Minimum-System study in response to Staff Data Request 1-2(d). In conducting his analyses, Mr. Heintz utilized VNG's estimates of current replacement costs for various sizes and types of distribution pipes. As noted earlier, Mr. Heintz assumed a minimum size pipe of 2-inch plastic. Based on this assumption, he then applied a current cost per foot for 2-inch plastic of $120.00 per foot. While the use of current costs as opposed to embedded costs is an acceptable approach,[21] Mr. Heintz's use of $120.00 per foot for 2-inch plastic immediately drew my attention.

Over the last few years, I have conducted and evaluated dozens of project feasibility studies concerning the extension of natural gas mains for East Coast utilities. Virtually all studies have utilized the installation of 2-inch plastic mains. Invariably, the total installed costs of these 2-inch plastic mains have been in the range of $40.00 to $60.00 per foot. As a result, in OAG 3-42, I requested the Company to provide the investment and footage of distribution mains by size and type of pipe installed (booked) during 2015 and 2016. The Company provided a detailed database of its property records by vintage year, by size, and by type of pipe. I then calculated the average *actual* installed cost per foot of 2-inch plastic mains during the last two years.[22] Based on the data provided in this response, the actual installed cost of 2-inch pipe is $38.43, which is only one-third that of the $120.00 per foot utilized by Mr. Heintz in his Minimum-System analysis. This is most important because it is the cost of the minimum size pipe that is

[21] Because of differences in vintage year installations and due to inflation, there is the possibility of unreliable results if embedded costs are not trended to current costs using reliable cost of reproduction indices. Another approach is to utilize current replacement costs for all sizes and types of pipe.

[22] I used two years of experience due to the possibility of a small number of work orders for some sizes and types of pipe that may have confronted abnormal circumstances. Moreover, inflation has been very low during the last couple of years.

used as the basis for determining the customer component. In other words, if the minimum size pipe is greatly overstated, the resulting customer percentage will be overstated.

I also evaluated Mr. Heintz's assumed replacement costs for the other sizes and types of pipe used in his Minimum-System analysis; i.e., those used in the denominator. Once again, I found dramatic differences in Mr. Heintz's assumed replacement costs from that actually experienced by VNG in the last two years. The following table provides a comparison of Mr. Heintz's assumed replacement costs per foot by size and type of pipe to those actually experienced by VNG over the last two years. This table also provides a comparison of the cost per foot ratio for each size and type of pipe to 2-inch plastic pipe:

TABLE 5
Comparison of Heintz Minimum-System Costs Per Foot
to VNG Actual Property Records

Per VNG Property Records[23]			Heintz Analysis[24] b/	
2015-2016	Average Cost	Ratio to 2" Plastic	Replacement Cost Per Foot	Ratio to 2" Plastic
2" Plastic	$38.43	1.00	$120.00	1.00
4" Plastic	$60.56	1.58	$125.00	1.04
6" Plastic	$114.00	2.97	$145.00	1.21
8" Plastic	$154.92	4.03	$195.00	1.63
2" Steel	$269.93	7.02	$135.00	1.13
4" Steel	$593.56	15.44	$135.00	1.13
6" Steel	Not meaningful [25]	--	$225.00	1.88
8" Steel	$487.59	12.69	$350.00	2.92
12" Steel	$258.43	6.72	$650.00	5.42
14" Steel	Not meaningful [25]	--	$950.00	7.92

As can be seen above, there are significant differences between Mr. Heintz's assumed replacement costs and those actually experienced by VNG in the last two years. Perhaps most importantly in terms of his Minimum-Size analysis is the vast differences in the ratios to 2-inch plastic pipe. These differences in the relationship to 2-inch pipe greatly impact the veracity of Mr. Heintz's analysis.

Q. WHAT WAS THE SOURCE OF MR. HEINTZ'S ASSUMED REPLACEMENT COSTS PER FOOT BY SIZE AND TYPE OF PIPE?

[23] Per response to OAG 3-41.

[24] Per response to Staff 1-2(d).

[25] Not meaningful as there were only 50 feet of 6" steel and 1 foot of 14" steel recorded.

A. In response to OAG 3-40, the Company indicated that the replacement costs provided to Mr. Heintz were determined by AGSC's (Atlanta Gas Service Company) engineering department.

Q. AS PART OF YOUR INVESTIGATION, DID YOU DISCOVER ADDITIONAL DATA ERRORS OR INCONSISTENCIES?

A. Yes. As noted earlier, Mr. Heintz produced his workpapers used to develop his Minimum-System study in response to Staff Data Request 1-2(d). In performing Minimum-System studies, one must also know the installed footage by size and type of pipe. Indeed, Mr. Heintz's workpapers include footage by size and type that he used in his analysis. I then compared these footages with VNG's detailed property records.

In OAG 3-41, I requested an electronic database of distribution mains by vintage year, the gross investment and footage by size and type of pipe. VNG provided this database of its mains property records and indicated in its written response as well as in a conference call with VNG that the Company did not start tracking pipe by size and type until 1997. As a result, the Company's property records reflect mains by size and type of pipe installed subsequent to 1997.[26] With this database, I was able to compare the footages contained in the Company's property records with those utilized by Mr. Heintz in his Minimum-System analysis. My Schedule GAW-5 provides a comparison of Mr. Heintz's quantities (footage) by size and type to those contained in VNG's actual property records. As can be seen in this Schedule, there are glaring differences. For example, Mr. Heintz only shows 668,926 feet of 2-inch plastic pipe whereas the

[26] The Company's property record database does include vintage years prior to 1997, however, this is not detailed by size and type of pipe.

Company's property records indicate 4,542,730 feet. Similarly, Mr. Heintz's analysis includes 4,615,020 feet of 2-inch steel pipe as compared to only 2,791 feet installed as per the Company's property records. Other very large differences include: 6-inch plastic; 8-inch plastic; 4-inch steel; 6-inch steel; 8-inch steel; and, 16-inch steel.

Q. HOW DO THESE SIGNIFICANT DIFFERENCES IMPACT MR. HEINTZ'S ANALYSIS?

A. Under the Minimum-System approach, it is the relationships between differences in not only the costs per foot but also the relationship of the quantity of various sizes of pipe that produces the resulting customer/demand split. To the extent that the quantity of various sizes and types of pipe are inaccurate (at least in relative terms), this will materially impact the Minimum-System results.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING MR. HEINTZ'S MINIMUM-SYSTEM STUDY?

A. Mr. Heintz's Minimum-System study should not be considered because: (1) his selected minimum size pipe of 2-inch plastic overstates the customer percentage due to the fact that 2-inch plastic pipe is installed to meet peak demand for these customers resulting in a double assignment of costs to small volume customer classes; and, (2) his data sources are in stark contrast to and conflict with the Company's own property records, and therefore are unreliable.

Q. HAVE YOU OR VNG CONDUCTED ALTERNATIVE CCOSS THAT MORE APPROPRIATELY REFLECT COST CAUSATION AND IS MORE FAIR AND REASONABLE TO ALL CUSTOMER CLASSES?

A. Yes. As part of the settlement in VNG's last rate case (Case No. PUE-2010-00142), the Company agreed to provide CCOSS based on both the P&A and 7/12 approach to allocate distribution mains. As explained earlier, these two methods are more consistent with cost causation and produce fair and reasonable results to all rate classes. In these regards, both the P&A and 7/12 methods assign no distribution mains based on customer counts. Furthermore, each of these methods assign some cost responsibility to interruptible customers but do not treat this class at the same level of cost responsibility as firm customers.

Q. PLEASE PROVIDE A COMPARISON OF THE COMPANY'S CCOSS RESULTS UNDER ITS AS-FILED CUSTOMER/DEMAND METHOD AS WELL AS UNDER ITS P&A AND 7/12 METHODS.

A. The following tables provide class rates of return at current rates under each of these methods as calculated by VNG:

TABLE 6
CCOSS Results as Calculated by VNG
Rate of Return at Current Rates

Class	Cust/Dem	P&A	7/12
Residential	3.90%	6.33%	6.06%
Back Up Generators	0.88%	5.47%	5.44%
Small General Firm Sales	2.64%	3.90%	4.03%
Large General Firm Sales	8.29%	5.27%	5.69%
Residential AC	26.56%	15.44%	6.15%
General AC	23.61%	9.19%	2.32%
Gas Lights	87.21%	51.97%	46.85%
High Load Factor Firm Delivery	15.15%	-0.42%	-0.68%
General Firm Delivery	26.81%	2.07%	-1.42%
NGV	48.34%	1.93%	0.21%
Seasonal High LF Firm Delivery	3.25%	-3.61%	-4.12%
New Facilities Interruptible Gas Del.	2.45%	-3.83%	-2.92%
Interruptible Gas Delivery	29.15%	-2.90%	-0.92%
Intrastate Pipeline Services	6.69%	6.72%	6.71%
Total Jurisdictional	4.67%	5.06%	5.08%

TABLE 7
CCOSS Results as Calculated by VNG
Indexed Rates of Return at Current Rates

Class	Cust/Dem	P&A	7/12
Residential	84%	125%	119%
Back Up Generators	19%	108%	107%
Small General Firm Sales	57%	77%	79%
Large General Firm Sales	177%	104%	112%
Residential AC	569%	305%	121%
General AC	506%	182%	46%
Gas Lights	1867%	1027%	922%
High Load Factor Firm Delivery	324%	-8%	-13%
General Firm Delivery	574%	41%	-28%
NGV	1035%	38%	4%
Seasonal High LF Firm Delivery	70%	-71%	-81%
New Facilities Interruptible Gas Del.	52%	-76%	-58%
Interruptible Gas Delivery	624%	-57%	-18%
Intrastate Pipeline Services	143%	133%	132%
Total Jurisdictional	100%	100%	100%

As can be seen above, there are some classes with directional similarities across all studies. However, for several classes, there are vast differences in the rate of return results across methodologies. To illustrate, the Residential AC, Gas Lighting, and Intrastate Pipeline classes' exhibit significantly higher rates of return than the system average regardless of methodology employed, while the Seasonal High Load Factor Delivery and New Facilities Interruptible Gas Delivery classes' exhibit significantly lower rates of return under all methods. Depending on the methodology, classes such as Backup Generators, High Load Factor Firm Delivery, Natural Gas Vehicles, and Interruptible Gas Delivery classes' vary tremendously depending on the method used to allocate distribution mains-related costs.

Q. HAVE YOU MADE ANY ADJUSTMENTS TO THE COMPANY'S CCOSS UTILIZING THE P&A AND 7/12 METHODS TO ALLOCATE DISTRIBUTION MAINS?

A. Yes. Consistent with the Company's jurisdictional cost study, Mr. Heintz allocated distribution Land & Land Rights and Structures & Improvements based on number of customers. As discussed earlier, it is more appropriate to allocate these rate base accounts based on mains investment. In this regard, there is only a minimal impact on jurisdictional class rates of return with this adjustment. Nonetheless, the class rates of return under current rates allocating these accounts based on distribution mains are provided in the tables below:

TABLE 8
CCOSS Results as Adjusted for Accounts 374 and 375
Rates of Return at Current Rates

Class	Cust/Dem	P&A	7/12
Residential	3.92%	6.42%	6.13%
Back Up Generators	0.94%	5.89%	5.86%
Small General Firm Sales	2.63%	3.90%	4.03%
Large General Firm Sales	8.08%	5.08%	5.48%
Residential AC	26.68%	15.27%	5.97%
General AC	23.33%	8.91%	2.18%
Gas Lights	88.93%	51.87%	46.61%
High Load Factor Firm Delivery	14.76%	-0.50%	-0.76%
General Firm Delivery	26.25%	1.92%	-1.47%
NGV	48.52%	1.80%	0.12%
Seasonal High LF Firm Delivery	3.18%	-3.60%	-4.08%
New Facilities Interruptible Gas Del.	2.45%	-3.91%	-2.92%
Interruptible Gas Delivery	29.17%	-2.91%	-0.98%
Intrastate Pipeline Services	6.69%	6.72%	6.71%
Total Jurisdictional	4.67%	5.06%	5.08%

TABLE 9
CCOSS Results as Adjusted for Accounts 374 and 375
Indexed Rates of Return at Current Rates

Class	Cust/Dem	P&A	7/12
Residential	84%	127%	121%
Back Up Generators	20%	116%	115%
Small General Firm Sales	56%	77%	79%
Large General Firm Sales	173%	100%	108%
Residential AC	571%	302%	117%
General AC	500%	176%	43%
Gas Lights	1904%	1025%	917%
High Load Factor Firm Delivery	316%	-10%	-15%
General Firm Delivery	562%	38%	-29%
NGV	1039%	35%	2%
Seasonal High LF Firm Delivery	68%	-71%	-80%
New Facilities Interruptible Gas Del.	52%	-77%	-58%
Interruptible Gas Delivery	625%	-57%	-19%
Intrastate Pipeline Services	143%	133%	132%
Total Jurisdictional	100%	100%	100%

The class rate of return relationships are relatively unaffected with my alternative method to allocated Accounts 374 and 375 such that this adjustment is immaterial for CCOSS purposes.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING CCOSS FOR THIS CASE?

A. While no CCOSS can be considered surgically precise, Mr. Heintz's study results in significant biases against the small volume user classes such as residential and small commercial. The reasons for this is that he has significantly under-assigned cost responsibility to the interruptible classes by assigning no distribution mains cost responsibility to these customers and at the same time over-assigns cost responsibility to the residential class by allocating distribution mains costs partially on a faulty Minimum-System study. As a result, the Commission should rely upon the P&A and 7/12 methods for purposes of assigning class revenue responsibility.

IV. CLASS REVENUE DISTRIBUTION

Q. HOW DOES VNG PROPOSE TO DISTRIBUTE ITS REQUESTED OVERALL $30.7 MILLION REVENUE INCREASE TO RATE CLASSES?

A. VNG witness Heintz sponsors the Company's class revenue distribution proposal wherein the following table provides his recommended increases in base rates by class:

TABLE 10
VNG Proposed Class Revenue Increases

Class	Rate Schedule	Current Base Rate Revenue	Proposed Increase	Percent Increase	Percent of Sys. Avg.
Residential	1	$103,731,469	$26,429,239	25.48%	121%
General - Backup Generators	2.A	$105,810	$12,696	12.00%	57%
Small General Firm Sales	2.B	$7,337,075	$1,869,336	25.48%	121%
Large General Firm Sales	2.C	$14,832,256	$1,779,667	12.00%	57%
Residential AC	3	$2,266	$272	12.00%	57%
General AC	4	$60,970	$7,316	12.00%	57%
Gas Lights	5	$30,974	$3,096	10.00%	48%
HLF Firm Delivery	6	$1,114,157	$133,626	11.99%	57%
General Firm Delivery	7	$1,739,049	$208,670	12.00%	57%
Interruptible Gas Delivery	9	$1,955,048	$234,584	12.00%	57%
NGV	11-14	$224,315	$22,416	9.99%	48%
Seasonal High Load Firm Del.	15	$299,480	$0	0.00%	0%
New Facilities Interruptible	16	$1,951,167	$0	0.00%	0%
Intrastate Transmission	PT-1/HRX	$12,955,220	$0	0.00%	0%
Total Base Rate Revenue		$146,339,256	$30,700,918	20.98%	100%
Other Revenue		$2,887,475	$0	0.00%	
Total Non-Gas Revenue		$149,226,731	$30,700,918	20.57%	
Rate Design Rounding			$1,097		
Requested Revenue Increase			$30,702,015		

Q. IS MR. HEINTZ'S PROPOSED CLASS REVENUE DISTRIBUTION REASONABLE?

A. No. While class revenue responsibility should reflect several criteria, CCOSS results should be considered within the determination of class revenue responsibility. Mr.

Heintz's proposed class revenue increases are inconsistent with class cost allocations. For example, while the residential class exhibits a rate of return greater than the system average (i.e., an indexed rate of return of greater than 100%), he proposes to increase this class' base rate revenues by 121% of the system average revenue increase. Similarly, the HLF Firm Delivery (Rate 6), General Firm Delivery (Rate 7), Interruptible Gas Delivery (Rate 9), Natural Gas Vehicles (Rates 11-14), Seasonal High Load Firm Delivery (Rate 15), and New Facilities Interruptible (Rate 16) classes all exhibit significantly deficient class rates of return, yet, Mr. Heintz recommends either no increase or only about half of the system average percentage increase to these classes. As a result, Mr. Heintz's recommended class increases are diametrically opposed to reasonable cost of service.

Q. HAVE YOU DEVELOPED A MORE APPROPRIATE CLASS REVENUE DISTRIBUTION THAT RECOGNIZES CCOSS AS WELL AS OTHER ACCEPTED RATEMAKING PRINCIPLES SUCH AS GRADUALISM?

A. Yes. In developing my recommended class revenue distribution, I have utilized the Company's requested overall revenue increase of $30.7 million. In this way, I provide an apples-to-apples comparison with Mr. Heintz's proposed revenue increases. However, as will be discussed later in my testimony, I will provide a mechanism to distribute the overall increase authorized by the Commission.

Because CCOSS are not surgically precise, I have relied upon studies only as a guide in evaluating class revenue responsibility. As noted above, several classes have significantly deficient rates of return at current rates indicating that they should sustain a larger percentage increase than the system-wide average percentage increase. Similarly, those classes that are producing significantly higher rates of return than the system average should receive increases less than the overall system percentage increase. Furthermore, given the fact that much of the Company's requested increase reflects additional plant in service that is used to serve all customers as well as increased expenses incurred in a joint manner; e.g., salaries and wages, it is appropriate that all classes receive some increase as a result of this rate case.

In developing my recommendation, I increased the High Load Factor Firm Delivery, General Firm Delivery, Natural Gas Vehicles, Seasonal High Load Factor Firm Delivery, New Facilities Interruptible Gas Delivery and Interruptible Gas Delivery classes by 150% of the system average percentage increase as these classes' revenues are significantly deficient (31.47%). Conversely, the Residential AC and Gas Lighting classes are contributing significantly high rates of return such that their classes are increased at 50% of the system average percentage increase (10.49%). Three rate classes (General Backup Generators, Large General Firm Sales, and General AC) are contributing profits at about the same level of the system average such that these classes are increased at the system average percentage increase of 20.98%. Small General Firm Sales is contributing less than the system average rate of return but not as deficient as the earlier mentioned classes with significantly deficient profit contributions. Therefore, this class was increased at 125% of the system average percent increase (26.22%). Similarly, Intrastate Transmission's rate of return is somewhat higher than the system average such that this class receives 75% of the system average percentage increase (15.73%). Finally, and due to the large size of residential service, this class is treated as the residual in order to collect their required total increase. This results in a 20.53% increase to the residential class (98% of the system average percentage increase).

V. RESIDENTIAL RATE DESIGN

Q. PLEASE EXPLAIN THE STRUCTURE AND LEVEL OF VNG'S CURRENT RESIDENTIAL BASE (NON-GAS COST) RATES.

A. Currently, VNG's residential rate Schedule 1 is comprised of a fixed monthly customer charge of $11.00 and a slightly declining two-block usage charge of $0.37740 for the first 35 CCF and $0.34858 CFF for all additional CCDF of gas consumed. In addition, residential customers are currently subject to a fixed fee of $3.15 per month associated with the SAVE Act, wherein such costs associated with the SAVE Act will be rolled into base rates at the conclusion of this case.

Q. WHAT IS VNG'S PROPOSED STRUCTURE AND LEVEL OF RESIDENTIAL BASE RATES?

A. VNG proposes to increase the base customer charge of $11.00 per month by 82% to $20.00 per month. For volumetric usage charges, VNG proposes to eliminate its declining block rate structure to a flat usage rate for all gas consumed.

Q. WHAT EVIDENCE DOES THE COMPANY PROVIDE TO SUPPORT ITS REQUESTED 82% INCREASE TO THE RESIDENTIAL CUSTOMER CHARGE?

A. By and large, Mr. Heintz asserts that fixed costs should be recovered through fixed charges. Because the vast majority of VNG's sunk or short-run costs are fixed in nature, he claims that a substantial amount of the Company's non-gas revenues should be collected through fixed charges. Specifically on page 17 of his direct testimony, Mr. Heintz claims:

> Toward this goal, it is generally an unsound ratemaking practice to recover a substantial portion of fixed costs, such as customer-related costs which bear no relationship to customer consumption patterns, in the volumetric portion of the rate structure. Recovery of fixed costs via volumetric rates adversely impacts earnings stability because the revenues generated from customers' volumetric use of gas can be extremely sensitive to the vagaries of weather patterns and changing consumption characteristics due to energy conservation efforts among other factors. Recovery of utility fixed costs in volumetric rates sends uneconomic price signals to consumers that impede their ability to make well-founded energy consumption decisions based on the actual costs of various types and levels of utility distribution service.

Q. DO YOU AGREE WITH MR. HEINTZ'S ASSERTIONS THAT FIXED COSTS SHOULD BE RECOVERED FROM FIXED CHARGES?

A. No. I strongly disagree with Mr. Heintz's understanding of economic price theory and how efficient pricing prevails in competitive markets. This is most important as it is often said that regulation should serve as a surrogate to competition to the largest extent possible. Indeed, the Company's objective to collect a large percentage of its sunk investment costs (fixed costs) through fixed charges, as well as its proposed increases to such charges, violate the regulatory principle of gradualism, violate the economic theory of efficient competitive pricing, and are contrary to effective conservation efforts.

Q. **PLEASE EXPLAIN.**

A. The most basic tenet of competition is that prices determined through a competitive market ensure the most efficient allocation of society's resources. Because public utilities are generally afforded monopoly status under the belief that resources are better utilized without duplicating the fixed facilities required to serve consumers, a fundamental goal of regulatory policy is that regulation should serve as a surrogate for competition to the greatest extent practical.[27] As such, the pricing policy for a regulated public utility should mirror those of competitive firms to the greatest extent practical.

Under economic theory, efficient price signals result when prices are equal to marginal costs.[28] It is well known that costs are variable in the long run. Therefore, efficient pricing results from the incremental variability of costs even though a firm's short-run cost structure may include a high level of sunk or "fixed" costs or be reflective of excess capacity. Indeed, competitive market-based prices are generally structured based on usage; i.e. volume-based pricing. For example, an oil refinery costs well over a billion dollars to build such that its cost structure is largely comprised of sunk, or fixed, costs, but these costs are recovered one gallon at a time.

Q. PLEASE BRIEFLY EXPLAIN THE ECONOMIC PRINCIPLES OF EFFICIENT PRICE THEORY AND HOW SHORT-RUN FIXED COSTS ARE RECOVERED UNDER SUCH EFFICIENT PRICING.

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[27] James C. Bonbright, et al., *Principles of Public Utility Rates*, p. 141 (Second Edition, 1988).

[28] Strictly speaking, efficiency is achieved only when there is no excess capacity such that short-run marginal costs equal long-run marginal costs. In practice, there is usually at least some excess capacity present such that pricing based on long-run marginal costs represents the most efficient utilization of resources.

A. Perhaps the best known micro-economic principle is that in competitive markets (i.e., markets in which no monopoly power or excessive profits exist), prices are equal to marginal cost. Marginal cost is equal to the incremental change in cost resulting from an incremental change in output. A full discussion of the calculus involved in determining marginal costs is not necessary here. However, it is readily apparent that because marginal costs measure the changes in costs with output, short-run "fixed" costs are irrelevant in efficient pricing. This is not to say that efficient pricing does not allow for the recovery of short-run fixed costs. Rather, they are reflected within a firm's production function such that no excess capacity exists and that an increase in output will require an increase in costs – including those considered "fixed" from an accounting perspective. As such, under efficient pricing principles, marginal costs capture the variability of costs, and prices are variable because prices equal these costs.

Q. PLEASE EXPLAIN HOW EFFICIENT PRICING PRINCIPLES ARE APPLIED TO THE NATURAL GAS DISTRIBUTION INDUSTRY.

A. Universally, utility marginal cost studies include three separate categories of marginal costs: demand; energy; and customer. Consistent with the general concept of marginal costs, each of these costs varies with incremental changes. Marginal demand costs measure the incremental change in costs resulting from an incremental change in peak load (demand). Marginal energy (commodity) costs measure the incremental change in costs resulting from an incremental change in MCF (energy) consumption. Marginal customer costs measure the incremental change in costs resulting from an incremental change in number of customers.

Particularly relevant here is understanding what costs are included within, and the procedures used to determine, marginal customer costs. Since marginal customer costs reflect the measurement of how costs vary with the number of customers, they only include those costs that directly vary as a result of adding a new customer.

Q. PLEASE EXPLAIN HOW THIS THEORY OF COMPETITIVE PRICING SHOULD BE APPLIED TO REGULATED PUBLIC UTILITIES SUCH AS VNG.

A. Due to VNG's investment in system infrastructure, there is no debate that many of its short-run costs are fixed in nature. However, as discussed above, efficient competitive prices are established based on long-run costs, which are entirely variable in nature.

Marginal cost pricing only relates to efficiency. This pricing does not attempt to address fairness or equity. Fair and equitable pricing of a regulated monopoly's products and services should reflect the benefits received for the goods or services. In this regard, those that receive more benefits should pay more in total than those who receive fewer benefits. Regarding natural gas usage, the level of consumption is the best and most direct indicator of benefits received. Thus, volumetric pricing promotes the fairest pricing mechanism to customers and to the utility.

The above philosophy has consistently been the belief of economists, regulators, and policy makers for generations. For example, consider utility industry pricing in the 1800s, when the industry was in its infancy. Customers paid a fixed monthly fee and consumed as much of the utility commodity/service as they desired (usually water). It soon became apparent that this fixed monthly fee rate schedule was inefficient and unfair. Utilities soon began metering their commodity/service and charging only for the amount actually consumed. In this way, consumers receiving more benefits from the utility paid more, in total, for the utility service because they used more of the commodity.

Q. IS THE NATURAL GAS DISTRIBUTION INDUSTRY UNIQUE IN ITS COST STRUCTURES, WHICH ARE COMPRISED LARGELY OF FIXED COSTS IN THE SHORT-RUN?

A. No. Most manufacturing and transportation industries are comprised of cost structures predominated with "fixed" costs. These fixed costs, also called "sunk" costs, are primarily comprised of investments in plant and equipment. Indeed, virtually every capital-intensive industry is faced with a high percentage of so-called fixed costs in the short run. Prices for competitive products and services in these capital-intensive industries are invariably established on a volumetric basis, including those that were once regulated, e.g., motor transportation, airline travel, and rail service.

Accordingly, VNG's position that its fixed costs should be recovered through fixed monthly charges is incorrect. Pricing should reflect the Company's long-run costs, wherein all costs are variable or volumetric in nature, and users requiring more of VNG's products and services should pay more than customers who use less of these products and services. Stated more simply, those customers who conserve or are otherwise more energy efficient, or those who use less of the commodity for any reason, should pay less than those who use more natural gas.

Q. HOW ARE HIGH FIXED CUSTOMER CHARGE RATE STRUCTURES CONTRARY TO EFFECTIVE CONSERVATION EFFORTS?

A. High fixed charge rate structures actually promote additional consumption because a consumer's price of incremental consumption is less than what an efficient price structure would otherwise be. A clear example of this principle is exhibited in the natural gas transmission pipeline industry. As discussed in its well-known Order 636, FERC's adoption of a "Straight Fixed Variable" ("SFV") pricing method[29] was a result of national policy (primarily that of Congress) to encourage increased use of domestic natural gas by promoting additional interruptible (and incremental firm) gas usage. FERC's SFV pricing mechanism greatly reduced the price of incremental (additional) natural gas consumption. This resulted in significantly increasing the demand for, and use of, natural gas in the United States after Order 636 was issued in 1992.

FERC Order 636 had two primary goals. The first goal was to enhance gas competition at the wellhead by completely unbundling the merchant and transportation functions of pipelines.[30] The second goal was to encourage the increased consumption of natural gas in the United States. In Order 636's introductory statement, FERC stated:

> The Commission's intent is to further "facilitat[e] the unimpeded operation of market forces to stimulate the production of natural gas... [and thereby] contribute to reducing our Nation's dependence upon imported oil...."[31]

With specific regard to the SFV rate design adopted in Order 636, FERC stated:

> Moreover, the Commission's adoption of SFV should maximize pipeline throughput over time by allowing gas to compete with alternate fuels on a timely basis as the prices of alternate fuels change. The Commission

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[29] Under SFV pricing, customers pay a fixed charge that is designed to recover all of the utility's fixed costs.

[30] Federal Energy Regulatory Commission, Docket Nos. RM91-11-001 and RM87-34-065, Order No. 636 (Apr. 9, 1992), p. 7.

[31] *Id.* at 8 (quoting S. Rep. No. 39, 101st Cong., 1st Sess., at p. 2).

> believes it is beyond doubt that it is in the national interest to promote the use of clean and abundant gas over alternate fuels such as foreign oil. SFV is the best method for doing that.[32]

Indeed, FERC's objective to increase natural gas consumption through the use of SFV rate design was the genesis of utilities beginning to argue the misguided notion that fixed costs should somehow be recovered from fixed charges. That is, such assertions or claims were never made by utility rate design analysts until FERC Order 636 and the implementation of SFV rate design. As a result of this misunderstanding of economics and public policy, some public utilities have argued for SFV residential pricing (or increased reliance on fixed charges), claiming a need for enhanced fixed charge revenues. To support their claim, the companies argue that because retail rates have been historically volumetric-based, there has been a disincentive for utilities to promote conservation or encourage reduced consumption. However, FERC's objective in adopting SFV pricing suggests the exact opposite. The price signal that results from SFV pricing is meant to promote additional consumption, not reduce consumption. Thus, a rate structure that is heavily based on a fixed monthly customer charge sends an even stronger price signal to consumers to use more energy.

Q. AS A PUBLIC POLICY MATTER, WHAT IS THE MOST EFFECTIVE TOOL THAT REGULATORS HAVE TO PROMOTE COST EFFECTIVE CONSERVATION AND THE EFFICIENT UTILIZATION OF RESOURCES?

A. Unquestionably, one of the most important and effective tools that this, or any, regulatory Commission has to promote conservation is developing rates that send proper price

[32] *Id.* at 128-29 (internal citations omitted).

signals to conserve and utilize resources efficiently. A pricing structure that is largely fixed, such that customers' effective prices do not properly vary with consumption, promotes the inefficient utilization of resources. Pricing structures that are weighted heavily on fixed charges are much more inferior from a conservation and efficiency standpoint than pricing structures that require consumers to incur more cost with additional consumption.

Q. A CUSTOMER'S TOTAL NATURAL GAS BILL IS COMPRISED OF A BASE RATE COMPONENT AND A PURCHASED GAS CLAUSE COMPONENT. THE PURCHASED GAS CLAUSE IS VOLUMETRICALLY-PRICED AND REPRESENTS A SIGNIFICANT PORTION OF A CUSTOMER'S TOTAL BILL. DOES THE VOLUMETRIC PRICING OF THESE COMPONENTS ELIMINATE THE NEED FOR A PROPER PRICING SIGNAL?

A. No, certainly not. The fact that significant revenue may be collected volumetrically does not lessen the need for a reasonable rate design.

Q. NOTWITHSTANDING THE EFFICIENCY REASONS AS TO WHY REGULATION SHOULD SERVE AS A SURROGATE FOR COMPETITION, ARE THERE OTHER RELEVANT ASPECTS TO THE PRICING STRUCTURES IN COMPETITIVE MARKETS *VIS A VIS* THOSE OF REGULATED UTILITIES?

A. Yes. In competitive markets, consumers, by definition, have the ability to choose various suppliers of goods and services. Consumers and the market have a clear preference for

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volumetric pricing. Utility customers are not so fortunate in that the local utility is a monopoly. The only reason utilities are able to seek pricing structures with high fixed monthly charges is due to their monopoly status. In my opinion, this is a critical consideration in establishing utility pricing structures. Competitive markets and consumers in the United States have demanded volumetric-based prices for generations. A regulated utility's pricing structure should not be allowed to counter the collective wisdom of markets and consumers simply because of its market power.

Q. IN YOUR OPINION, SHOULD THE STRUCTURE OF NATURAL GAS DISTRIBUTION RATES BE BASED ENTIRELY ON VOLUMETRIC RATES?

A. No. Consistent with economic theory as well as the accepted practice of regulators for generations, it is appropriate for natural gas distribution rates to include a relatively small fixed monthly customer charge. In this regard, fixed monthly charges should only reflect the direct costs to connect and maintain a customer's account. As such, customer charges should only reflect the costs of service lines, meters, meter reading, customer records and billing. Customer charges should not include any overhead costs, as these are simply the cost of doing business, nor should they include any costs of mains.

Q. HAS MR. HEINTZ CONDUCTED ANY ANALYSES AS TO WHAT COSTS SHOULD BE REFLECTED WITHIN THE RESIDENTIAL CUSTOMER CHARGE?

A. Yes. Within his CCOSS, Mr. Heintz has classified all VNG costs as either demand-related, customer-related, or commodity-related. These classification "buckets" reflect

VNG's fully allocated costs including numerous general and overhead costs such as general plant and administrative and general expenses. These overhead costs are then classified as partially demand-related, customer-related, and commodity-related. Moreover, Mr. Heintz has included 43.60% of distribution mains costs within his customer classification bucket. As such, his so-called customer costs include a myriad of allocated overhead expenses that are required for VNG to operate its business as well as a significant portion of the Company's distribution mains investments. Mr. Heintz's calculations result in a residential customer-related classification revenue requirement of $28.12 per month. As a result of Mr. Heintz classifying a multitude of costs that should not be collected from fixed monthly customer charges, he has greatly overstated his "customer" costs.

Q. HAVE YOU CONDUCTED AN ANALYSIS OF THE APPROPRIATE LEVEL OF RESIDENTIAL CUSTOMER CHARGES FOR VNG?

A. Yes. Customer charges should only reflect those costs required to connect and maintain a customer's account. I have conducted a direct customer cost analysis for VNG's residential customers, which is provided in my Schedule GAW-6. In developing my residential customer cost, I have utilized the Company's capital structure, cost of debt, as well as its requested return on equity of 10.25%. In order to provide an understanding of the sensitivity of differing rates of return, I also calculate my residential customer cost on an authorized rate of return of 9.5%. However, because customer charges reflect guaranteed revenue recovery to the Company, there is virtually no business risk associated with customer charges such that the true cost of capital for fixed charges is substantially lower than the overall ROE authorized by the Commission in this case. As indicated in my Schedule GAW-6, I have determined that the direct residential customer cost is in the range of $10.49 to $10.84 per month.

Q. HAS THIS COMMISSION RECENTLY PROVIDED GUIDANCE AS IT RELATES TO THE DETERMINATION OF FIXED MONTHLY CUSTOMER (SYSTEM) CHARGES FOR NGDCs?

A. Yes. In the Commission's August 21, 2015 Final Order in Case No. PUE-2014-00020 involving Columbia Gas of Virginia, it adopted the exact same methodology that I am using in this case to determine that maximum level of residential customer charges. Specifically, the Commission adopted the following Hearing Examiner's recommendation:

> Consumer Counsel's recommended customer charges, which include only the cost to connect the customer to the Company's distribution system, administer the account, bill the customer, and SAVE- or ESAC-related service riser and meter replacement costs, are reasonable.[33]

In making this recommendation, the Hearing Examiner found as follows:

> I agree with Consumer Counsel that the Company's distribution system is required to deliver natural gas to its customers, and the cost of that distribution system should be recovered in the cost of the commodity sold. In other words, I find the cost of the Company's distribution system should be recovered through its volumetric rates. This finding is consistent with the Commission's longstanding position regarding customer charges. It is a simple fact that not all residential customers are the same. Some may take gas service to operate a decorative fireplace, while others may use gas to heat their homes, hot water, swimming pools, and as fuel for cooking. The Company's intra-class subsidy argument cuts both ways. When distribution system costs are included in the fixed customer charge, low usage customers subsidize high usage customers, and when the costs are included in volumetric rates, high usage customers

[33] *Application of Columbia Gas of Virginia, Inc. For authority to increase rates and charges and to revise the terms and conditions applicable to gas service*, Case No. PUE-2014-00020, Final Order (Aug. 21, 2015).

> subsidize low usage customers. There is, however, one common understanding among consumers – the more you buy, the more you pay. There is a reason the customer charge methodology of including only the cost of connecting the customer to the distribution system, administering the account, and billing the customer, while recovering all other costs in the volumetric rate, has withstood the test of time. Given the differences among customers of the same class, it is the fairest way for the Company to recover its costs. Everyone in the same class pays the same percentage of distribution system costs in each Mcf or Dth of gas that they purchase from the Company.
>
> Accordingly, I find Consumer Counsel's recommended customer charges, which include only the costs to connect the customer to the Company's distribution system, administer the account, bill the customer, and SAVE- or ESAC-related service riser and meter replacement costs, are reasonable.[34]

To be clear, the Hearing Examiner's reference to "distribution system costs" are the same as those referred to by Mr. Heintz as "fixed costs" in this case.

Q. DID THE COMMISSION'S ORDER IN CASE NO. PUE-2014-00020 ESTABLISH A BRIGHT-LINE RULE FOR DETERMINING FIXED CUSTOMER CHARGES?

A. No. The Commission's Order in Case No. PUE-2014-00020 specifically stated that it was not approving a "bright-line rule." Rather, the Commission's findings in that case were based on the specific facts as presented in that proceeding and that the Commission has historically exercised discretion in determining the appropriate level of customer charges based on the facts and circumstances of each case.

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[34] *Application of Columbia Gas of Virginia, Inc. For authority to increase rates and charges and to revise the terms and conditions applicable to gas service*, Case No. PUE-2014-00020, Report on Remand of Michael D. Thomas, Hearing Examiner at 19-20 (June 30, 2015) (adopted by the Commission in the Final Order).

part 2

Schedule GAW-1

Background and Experience Profile of Glenn A. Watkins

Q. **IN YOUR OPINION, ARE THERE ANY FACTS OR CIRCUMSTANCES IN THIS CASE THAT WOULD CAUSE THE COMMISSION TO DEVIATE FROM ITS OPINION IN CASE NO. PUE-2014-00020?**

A. No. The facts and circumstances in this case mirror those in the Columbia Gas of Virginia case. Indeed, the approaches used and arguments made, by Mr. Heintz, are identical to those made by Columbia Gas of Virginia's witnesses that were rejected.

Q. **WHAT IS YOUR RECOMMENDATION REGARDING FIXED MONTHLY CUSTOMER CHARGES FOR VNG'S RESIDENTIAL CUSTOMERS?**

A. Even though my calculated residential customer charge range of $10.49 to $10.84 per month is somewhat less than the current rate of $11.00 per month, I recommend that the existing residential customer charge be maintained at its current level of $11.00 per month.

Q. **DOES THIS COMPLETE YOUR TESTIMONY?**

A. Yes.

BACKGROUND & EXPERIENCE PROFILE
GLENN A. WATKINS
VICE PRESIDENT/SENIOR ECONOMIST
TECHNICAL ASSOCIATES, INC.

EDUCATION

1982 - 1988	M.B.A., Virginia Commonwealth University, Richmond, Virginia
1980 - 1982	B.S., Economics; Virginia Commonwealth University
1976 - 1980	A.A., Economics; Richard Bland College of The College of William and Mary, Petersburg, Virginia

POSITIONS

Jan. 2017-Present	President/Senior Economist, Technical Associates, Inc.
Mar. 1993-Dec. 2016	Vice President/Senior Economist, Technical Associates, Inc. (Mar. 1993-June 1995 Traded as C. W. Amos of Virginia)
Apr. 1990-Mar. 1993	Principal/Senior Economist, Technical Associates, Inc.
Aug. 1987-Apr. 1990	Staff Economist, Technical Associates, Inc., Richmond, Virginia
Feb. 1987-Aug. 1987	Economist, Old Dominion Electric Cooperative, Richmond, Virginia
May 1984-Jan. 1987	Staff Economist, Technical Associates, Inc.
May 1982-May 1984	Economic Analyst, Technical Associates, Inc.
Sep. 1980-May 1982	Research Assistant, Technical Associates, Inc.

EXPERIENCE

I. <u>Public Utility Regulation</u>

A. <u>Costing Studies</u> -- Conducted, and presented as expert testimony, numerous embedded and marginal cost of service studies. Cost studies have been conducted for electric, gas, telecommunications, water, and wastewater utilities. Analyses and issues have included the evaluation and development of alternative cost allocation methods with particular emphasis on ratemaking implications of distribution plant classification and capacity cost allocation methodologies. Distribution plant classifications have been conducted using the minimum system and zero-intercept methods. Capacity cost allocations have been evaluated using virtually every recognized method of allocating demand related costs (e.g., single and multiple coincident peaks, non-coincident peaks, probability of loss of load, average and excess, and peak and average).

Embedded and marginal cost studies have been analyzed with respect to the seasonal and diurnal distribution of system energy and demand costs, as well as cost effective approaches to incorporating energy and demand losses for rate design purposes. Economic dispatch models have been evaluated to determine long range capacity requirements as well as system marginal energy costs for ratemaking purposes.

B. <u>Rate Design Studies</u> -- Analyzed, designed and provided expert testimony relating to rate structures for all retail rate classes, employing embedded and marginal cost studies. These rate structures have included flat rates, declining block rates, inverted block rates, hours use of demand blocking, lighting rates, and interruptible rates. Economic development and special industrial rates have been developed in recognition of the competitive environment for specific customers. Assessed alternative time differentiated rates with diurnal and seasonal pricing structures. Applied Ramsey (Inverse Elasticity) Pricing to marginal costs in order to adjust for embedded revenue requirement constraints.

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C. Forecasting and System Profile Studies -- Development of long range energy (Kwh or Mcf) and demand forecasts for rural electric cooperatives and investor owned utilities. Analysis of electric plant operating characteristics for the determination of the most efficient dispatch of generating units on a system-wide basis. Factors analyzed include system load requirements, unit generating capacities, planned and unplanned outages, marginal energy costs, long term purchased capacity and energy costs, and short term power interchange agreements.

D. Cost of Capital Studies -- Analyzed and provided expert testimony on the costs of capital and proper capital structures for ratemaking purposes, for electric, gas, telephone, water, and wastewater utilities. Costs of capital have been applied to both actual and hypothetical capital structures. Cost of equity studies have employed comparable earnings, DCF, and CAPM analyses. Econometric analyses of adjustments required to electric utilities cost of equity due to the reduced risks of completing and placing new nuclear generating units into service.

E. Accounting Studies -- Performed and provided expert testimony for numerous accounting studies relating to revenue requirements and cost of service. Assignments have included original cost studies, cost of reproduction new studies, depreciation studies, lead-lag studies, Weather normalization studies, merger and acquisition issues and other rate base and operating income adjustments.

II. Transportation Regulation

A. Oil and Products Pipelines -- Conducted cost of service studies utilizing embedded costs, I.C.C. Valuation, and trended original cost. Development of computer models for cost of service studies utilizing the "Williams" (FERC 154-B) methodology. Performed alternative tariff designs, and dismantlement and restoration studies.

B. Railroads -- Analyses of costing studies using both embedded and marginal cost methodologies. Analyses of market dominance and cross-subsidization, including the implementation of differential pricing and inverse elasticity for various railroad commodities. Analyses of capital and operation costs required to operate "stand alone" railroads. Conducted cost of capital and revenue adequacy studies of railroads.

III. Insurance Studies

Conducted and presented expert testimony relating to market structure, performance, and profitability by line and sub-line of business within specific geographic areas, e.g. by state. These studies have included the determination of rates of return on Statutory Surplus and GAAP Equity by line - by state using the NAIC methodology, and comparison of individual insurance company performance vis a vis industry Country-Wide performance.

Conducted and presented expert testimony relating to rate regulation of workers compensation, automobile, and professional malpractice insurance. These studies have included the determination of a proper profit and contingency factor utilizing an internal rate of return methodology, the development of a fair investment income rate, capital structure, cost of capital.

Other insurance studies have included testimony before the Virginia Legislature regarding proper regulatory structure of Credit Life and P&C insurance; the effects on competition and prices resulting from proposed insurance company mergers, maximum and minimum expense multiplier limits, determination of specific class code rate increase limits (swing limits); and investigation of the reasonableness of NCCI=s administrative assigned risk plan and pool expenses.

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IV. Anti-Trust and Commercial Business Damage Litigation

Analyses of alleged claims of attempts to monopolize, predatory pricing, unfair trade practices and economic losses. Assignments have involved definitions of relevant market areas(geographic and product) and performance of that market, the pricing and cost allocation practices of manufacturers, and the economic performance of manufacturers' distributors.

Performed and provided expert testimony relating to market impacts involving automobile and truck dealerships, incremental profitability, the present value of damages, diminution in value of business, market and dealer performance, future sales potential, optimal inventory levels, fair allocation of products, financial performance; and business valuations.

MEMBERSHIPS AND CERTIFICATIONS

Member, Association of Energy Engineers (1998)
Certified Rate of Return Analyst, Society of Utility and Regulatory Financial Analysts (1992)
Member, American Water Works Association
National Association of Business Economists
Richmond Association of Business Economists
National Economics Honor Society

Public Version (1 Page Redacted)

Schedule GAW-2

Confidential
VNG Transmission System Map

Schedule GAW-3

OAG
Jurisdictional Cost Study Results

OAG Proposed
Virginia Natural Gas Company
Jurisdictional Cost Separation Study
Year Ended 09/30/16

FERC ACCT.	DETAIL OF RATE BASE As of 9/30/2016	TOTAL COSTS: Total VNG GAAP Basis	TOTAL COSTS: HRX Equity Adjustments	TOTAL COSTS: Total VNG Regulatory Basis	PIPELINE COSTS OF SERVICE: JUP-PT-1 pipeline Dept. 4032, 4009	HRX Pipeline: Ladysmith Dept. 4018	HRX Pipeline: Charles City Dept. 4017	HRX Pipeline: pipeline Dept. 4038	HRX Pipeline: Total HRX	VNG Lateral Dept. 4081	Yorktown Pipeline	Rock Trem	TOTAL Pipeline	NET VNG Retail	JURISDICTIONAL ALLOCATION: Allocation Factor Pipeline	Allocation Factor Retail	Non-Jurisdictional Pipeline	Non-Jurisdictional Retail	Non-Jurisdictional Total	Jurisdictional	Total VNG	Percent Jurisdictional
	GAS PLANT IN SERVICE																					
	INTANGIBLE PLANT																					
301.00	Organization	647,861		647,861					-				-	647,861		PLANT	-	57,543	57,543	590,318	647,861	91.12%
302.00	Franchises & Consents	2,058		2,058					-				-	2,058		PLANT	-	183	183	1,875	2,058	91.12%
303.00	Misc. Intangible Plant	19,758,662		19,758,662					-				-	19,758,662		PLANT	-	1,754,972	1,754,972	18,003,690	19,758,662	91.12%
	TOTAL INTANGIBLE PLANT	20,403,580	-	20,403,580	-	-	-	-	-	-	-	-	-	20,403,580			-	1,812,698	1,812,698	18,595,883	20,403,580	91.12%
	PRODUCTION PLANT																					
304.00	Land & Land Rights	20,961		20,961					-				-	20,961		DDIX*	-	2,322	2,322	18,639	20,961	88.92%
305.00	Structures and Improvements	1,788,259		1,788,259					-				-	1,788,259		DDIX*	-	198,101	198,101	1,590,158	1,788,259	88.92%
311.00	LG Equipment	5,797,516		5,797,516					-				-	5,797,516		DDIX*	-	642,240	642,240	5,155,276	5,797,516	88.92%
320.00	Other Equipment	549,591		549,591					-				-	549,591		DDIX*	-	60,883	60,883	488,708	549,591	88.92%
+	TOTAL PRODUCTION PLANT	8,156,327	-	8,156,327	-	-	-	-	-	-	-	-	-	8,156,327			-	903,546	903,546	7,252,781	8,156,327	88.92%
	NATURAL GAS STORAGE & PROCESSING																					
360	Land & Land Rights			-					-				-	-	.	DDIX*	-	-	-	-	-	0.00%
361	Structures & Improvements LNG	484,284		484,284					-				-	484,284		DDIX*	-	53,648	53,648	430,636	484,284	88.92%
363/364	Vaporizing Compressor, Meas.& Reg.	1,744,103		1,744,103					-				-	1,744,103		DDIX*	-	193,209	193,209	1,550,894	1,744,103	88.92%
+	TOTAL GAS STORAGE & PROCESSING PLANT	2,228,387	-	2,228,387	-	-	-	-	-	-	-	-	-	2,228,387			-	246,857	246,857	1,981,530	2,228,387	88.92%
	TRANSMISSION PLANT																					
365	Land/Rights-Of-Way*	14,215,668		14,215,668	5,481,464	42,680	520,901	2,459,481	3,023,061	4,748,361		962,782	14,215,668	-	XMSpec.	PKAVG	1,119,880	-	1,119,880	13,095,789	14,215,668	92.12%
366	Structures and Improvements	5,400,476		5,400,476	(236,080)	2,545,690	2,756,114	52,345	5,354,150	282,407			5,400,476	-	XMSpec.	PKAVG	480,813	-	480,813	4,919,664	5,400,478	91.10%
367	Mains	265,567,175	10,017,126	278,584,301	67,789,172	3,915,163	3,859,575	130,966,638	138,741,376	#########		15,776,533	278,584,301	0	XMSpec.	PKAVG	23,023,398	0	23,023,398	255,560,903	278,584,301	91.74%
368	Compressor Sta. Equipment	30,397,574	2,318,929	32,716,503	2,450	#########	16,970,098	447,989	32,714,053				32,716,503	-	XMSpec.	PKAVG	2,807,177	-	2,807,177	29,909,326	32,716,503	91.42%
369	Measurement & Reg Station Equip	5,884,259	3,840	5,888,099	4,151,975	80,839	90,856	1,199,313	1,371,008	301,943		63,172	5,888,099	-	XMSpec.	PKAVG	359,531	-	359,531	5,528,569	5,888,099	93.89%
370	Communication Equipment	242,399		242,399	242,399				-				242,399	-	XMSpec.	PKAVG	11,373	-	11,373	231,026	242,399	95.31%
371	Other Equipment	510,265		510,265		268,638	139,190	33,432	441,260			69,005	510,265	-	XMSpec.	PKAVG	34,949	-	34,949	475,316	510,265	93.15%
+	TOTAL TRANSMISSION PLANT	325,217,817	12,339,895	337,557,712	77,431,379	#########	24,336,735	135,159,199	181,644,909	#########	-	16,871,493	337,557,712	0			27,837,121	0	27,837,121	309,720,591	337,557,712	91.75%
	DISTRIBUTION PLANT																					
374	Land & Land Rights	6,752,316		6,752,316					-	44,817	37,281		82,098	6,670,219	XMSpec/PKAVG	PKAVG	7,100	880,339	887,439	5,864,878	6,752,316	86.86%
375	Structures & Improvements	9,934,466		9,934,466					-				-	9,934,466		PKAVG		1,311,155	1,311,155	8,623,310	9,934,466	86.80%
376	Mains	439,980,555		439,980,555					-	14,612	########		2,929,586	437,050,969	XMSpec/PKAVG	PKAVG	134,796	57,682,190	57,816,987	382,163,569	439,980,555	86.86%
376		-		-					-				-	-								
377	Compressor Station Equip.	5,349,796		5,349,796					-				-	5,349,796		THRU		819,495	819,495	4,530,302	5,349,796	84.68%
378	Measuring & Regulating Equip.	21,834,263		21,834,263					-	16,500			16,500	21,817,763	XMSpec/PKAVG	THRU	1,988	3,342,098	3,344,085	18,490,177	21,834,263	84.68%
379	Measuring & Regulating Equip.-City Gate	-		-					-				-	-						-	-	
380	Services	275,221,643		275,221,643			1,603						-	275,221,643		WTSERV		6,786,046	6,786,046	268,435,597	275,221,643	97.53%
381	Meters	48,434,605		48,434,605					-		71,384		71,384	48,363,221	XMSpec/PKAVG	WTMETER	3,258	3,295,334	3,298,592	45,136,013	48,434,605	93.19%
382	Meter Installations	18,085,742		18,085,742					-				-	18,085,742		WTMETER		1,232,312	1,232,312	16,853,430	18,085,742	93.19%
383	House Regulators	11,909,993		11,909,993					-	1,706			1,706	11,908,287	XMSpec/PKAVG	WTMETER	206	811,397	811,603	11,098,390	11,909,993	93.19%
384	House Regulator Installations	5,004,018		5,004,018					-	373			373	5,003,645	XMSpec/PKAVG	WTMETER	45	340,934	340,979	4,663,039	5,004,018	93.19%
385	Industrial Meas. & Reg. Station Equip.	-		-					-			-	-	-							-	
387	Other Equipment	1,563,139		1,563,139				2,816	2,816	14,387			17,203	1,545,936	XMSpec/PKAVG	THRU	2,000	236,810	238,810	1,324,329	1,563,139	84.72%
+	TOTAL DISTRIBUTION PLANT	844,070,536	-	844,070,536	-	-	1,603	2,816	2,816	92,395	########	-	3,118,850	840,951,686		-	149,392	76,738,111	76,887,503	767,183,033	844,070,536	90.59%

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OAG Proposed
Virginia Natural Gas Company
Jurisdictional Cost Separation Study
Year Ended 09/30/16

FERC ACCT.	DETAIL OF RATE BASE As of 9/30/2016	TOTAL COSTS: Total VNG GAAP Basis	TOTAL COSTS: HRX Equity Adjustments	TOTAL COSTS: Total VNG Regulatory Basis	PIPELINE COSTS OF SERVICE: JUP-PT-1 pipeline Dept. 4082, 4009	HRX Pipeline: Ladysmith Dept. 4018	HRX Pipeline: Charles City Dept. 4017	HRX Pipeline: pipeline Dept. 4038	Total HRX	VNG Lateral Dept. 4081	Yorktown Pipeline	Rock Tenn	TOTAL Pipeline	NET VNG Retail	Allocation Factor: Pipeline	Allocation Factor: Retail	JURISDICTIONAL ALLOCATION: Non-Jurisdictional Pipeline	Non-Jurisdictional Retail	Non-Jurisdictional Total	Jurisdictional	Total VNG	Percent Jurisdictional
	GENERAL PLANT								-													
389	Land & Land Rights	819,051		819,051					-				-	819,051		PLANT		72,748	72,748	746,303	819,051	91.12%
390	Structures & Improvements	8,325,798		8,325,798					-				-	8,325,798		PLANT		739,500	739,500	7,586,297	8,325,798	91.12%
391	Office Furniture & Equipment	6,916,598		6,916,598		256	250	1,690	2,196				2,196	6,914,402	XMSpec/PKAVG	PLANT	203	614,140	614,342	6,302,255	6,916,598	91.12%
392	Transportation Equipment	7,675,802		7,675,802					-				-	7,675,802		PLANT		681,768	681,768	6,994,035	7,675,802	91.12%
393	Stores Equipment	-		-					-				-	-		PLANT		-	-	-	-	
394	Tools, Shop & Garage Equipment	1,736,078		1,736,078		38,137	30,430		68,567				68,567	1,667,511	XMSpec/PKAVG	PLANT	5,638	148,109	153,747	1,582,330	1,736,078	91.14%
395	Laboratory Equipment			-					-				-	-		PLANT		-	-	-	-	
396	Power Operation Equipment	1,142,238		1,142,238					-				-	1,142,238		PLANT		101,454	101,454	1,040,784	1,142,238	91.12%
397	Communications Equipment	725,846		725,846					-		38,800		38,800	687,046	XMSpec/PKAVG	PLANT	1,771	61,024	62,794	663,051	725,846	91.35%
398	Miscellaneous Equipment	590,834		590,834					-				-	590,834		PLANT		52,478	52,478	538,356	590,834	91.12%
+	TOTAL GENERAL PLANT	27,932,245	-	27,932,245	-	38,393	30,680	1,690	70,762	-	38,800	-	109,562	27,822,682			7,612	2,471,221	2,478,833	25,453,412	27,932,245	91.13%
=	TOTAL GAS PLANT IN SERVICE	1,228,013,892	12,339,895	1,240,353,787	77,431,379	#########	24,369,018	135,163,705	181,720,090	#########	########	16,871,493	340,786,124	899,567,663			27,994,125	82,172,433	110,166,557	###########	###########	91.12%
	CONSTRUCTION WORK IN PROGRESS																					
377-378	Comp Stat/Meas -regulating Sta	296,973		296,973					-				-	296,973		THRU		45,491	45,491	251,482	296,973	84.68%
311-363	LNG+ Storage	180,139		180,139					-				-	180,139		DDDC		19,956	19,956	160,184	180,139	88.92%
365-371	Transmission	938,123		938,123	286,879			-	-	651,244			938,123	(0)	XMSpec.	PKAVG	91,908	(0)	91,908	846,215	938,123	90.20%
var.-378	Distribution	285,167		285,167									-	285,167		DISTPLT		25,976	25,976	259,191	285,167	90.89%
376	Mains	9,593,275		9,593,275					-				-	9,593,275		PKAVG		1,266,125	1,266,125	8,327,150	9,593,275	86.80%
380	Services	4,427,516		4,427,516					-				-	4,427,516		WTSERV		109,168	109,168	4,318,349	4,427,516	97.53%
381	Meters	909,624		909,624					-				-	909,624		WTMETER		61,979	61,979	847,645	909,624	93.19%
383	House regulators+meas sta	82,033		82,033					-				-	82,033		WTMETER		5,589	5,589	76,443	82,033	93.19%
var.	Land+Buildings+Structures	18,447		18,447					-				-	18,447		TPLANT		1,638	1,638	16,809	18,447	91.12%
	Computer/Office Furniture+ Equip.	58,597		58,597					-				-	58,597		TPLANT		5,205	5,205	53,393	58,597	91.12%
390-392	Construct+Fleet	455,594		455,594					-				-	455,594		TPLANT		40,465	40,465	415,128	455,594	91.12%
394	Tools	37,922		37,922					-				-	37,922		TPLANT		3,368	3,368	34,554	37,922	91.12%
397+398	Communication	24,074		24,074					-				-	24,074		TPLANT		2,138	2,138	21,936	24,074	91.12%
+	TOTAL CONSTRUCTION WORK IN PROGRESS	17,307,484	-	17,307,484	286,879	-	-	-	-	651,244	-	-	938,123	16,369,361			91,908	1,587,099	1,679,007	15,628,478	17,307,484	90.30%
+	ACQUISITION ADJUSTMENT-Net	165,293,601	-	165,293,601					-				-	165,293,601		PLANT	-	14,681,438	14,681,438	150,612,163	165,293,601	91.12%
=	TOTAL GAS PLANT INVESTMENT	1,410,614,977	12,339,895	1,422,954,872	77,718,258	#########	24,369,018	135,163,705	181,720,090	#########	########	16,871,493	341,724,247	1,081,230,625			28,086,033	98,440,970	126,527,002	###########	###########	91.11%

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OAG Proposed
Virginia Natural Gas Company
Jurisdictional Cost Separation Study
Year Ended 09/30/16

FERC ACCT.	DETAIL OF RATE BASE As of 9/30/2016	TOTAL COSTS Total VNG GAAP Basis	HRX Equity Adjustments	Total VNG Regulatory Basis	PIPELINE COSTS OF SERVICE JUP-PT-1 pipeline Dept. 4082, 4009	HRX Pipeline Ladysmith Dept. 4018	Charles City Dept. 4017	pipeline Dept. 4038	Total HRX	VNG Lateral Dept. 4081	Yorktown Pipeline	Rock Tenn	TOTAL Pipeline	NET VNG Retail
				-					-					
	ACCUMULATED PROVISION FOR DEPRECIATION													
301-303	Intangible Plant	19,118,657		19,118,657		-			-				-	19,118,657
304-364	Storage/Production Plant	4,259,566		4,259,566		-			-				-	4,259,566
365-371	Transmission Plant*	85,761,294	1,240,160	87,001,454	31,462,190	4,781,890	4,557,473	83,745	9,423,108	########		1,345,394	71,606,230	15,395,225
374-387	Distribution Plant	272,560,588		272,560,588		-	347		347	32,266	########		3,056,252	269,504,336
389-398	General Plant	5,850,601		5,850,601		5,884	4,581	2,090	12,354		38,800		51,154	5,799,447
									-				-	-
-	TOTAL ACCUMULATED PROVISION FOR DEPRECIATION	387,550,707	1,240,160	388,790,867	31,462,190	4,787,374	4,562,402	85,835	9,435,810	########	########	1,345,394		314,077,231
				-										
-	NET PLANT INVESTMENT	1,823,064,270	11,099,735	1,834,164,005	46,254,868	########	19,806,616	135,877,878	172,284,280	########	-	15,526,099	341,724,247	767,153,394
	COST FREE CAPITAL DEDUCTIONS													
	ACCUMULATED DEFERRED INCOME TAXES (13mo Avg.)													
	Bad Debts	216,206		216,206					-				-	216,206
	Book/Tax Difference Partnership Income	-		-					-				-	-
	NSP	44,557		44,557					-				-	44,557
	Misc./Deferred Reconciliation	183,413		183,413					-				-	183,413
	Accrued Postretirement Benefits	(3,730,127)		(3,730,127)					-				-	(3,730,127)
	Pension	13,341,496		13,341,496					-				-	13,341,496
	Liberalized Depreciation	(220,639,782)	-	(220,639,782)	(14,791,525)	(2,253,713)	(2,224,584)	(18,570,188)	(23,048,484)	(8,849,805)	-	(3,384,313)	(50,074,127)	(170,565,655)
	Amortization Goodwill	-		-					-				-	-
	Deferred Purchased Gas Adjustment	(1,915,649)		(1,915,649)					-				-	(1,915,649)
	CIAC and Customer Advances	-		-					-				-	-
	Engineering Costs	-		-					-				-	-
	Removal Costs	-		-					-				-	-
	Deductible G+A	-		-					-				-	-
	Regulatory Amortization	-		-					-				-	-
	Property State	(29,356,542)	-	(29,356,542)					-				-	(29,356,542)
	Environmental Response Cost	-		-					-				-	-
	Leasehold Improvements	469,836		469,836					-				-	469,836
	Insurance reserve	25,927		25,927					-				-	25,927
	Receipts Tax Adjustment	(15,024)		(15,024)					-				-	(15,024)
	Stock Options	-		-					-				-	-
	481(a) Deductible General & Administrative	(1,880,477)		(1,880,477)					-				-	(1,880,477)
	Rate Case	-		-					-				-	-
	Restricted Stock units	16,762		16,762					-				-	16,762
	Interest and Taxes Charged to Contruction	-		-					-				-	-
	Accrued Bonus	68,754		68,754					-				-	68,754
	Revenue Normalization Adj'mt	5,394		5,394					-				-	5,394
	APIC/Over/under collections, Other	(204,945)	-	(204,945)					-				-	(204,945)
	TOTAL ACCUMULATED DEFERRED INCOME TAXES	(243,370,201)	-	(243,370,201)	(14,791,525)	(2,253,713)	(2,224,584)	(18,570,188)	(23,048,484)	(8,849,805)	-	(3,384,313)	(50,074,127)	(193,296,075)
	Customer Advances for Construction								-				-	-
-	TOTAL COSTS FREE CAPITAL DEDUCTIONS	(243,370,201)	-	(243,370,201)	(14,791,525)	(2,253,713)	(2,224,584)	(18,570,188)	(23,048,484)	(8,849,805)	-	(3,384,313)	(50,074,127)	(193,296,075)

FERC ACCT.	DETAIL OF RATE BASE As of 9/30/2016	JURISDICTIONAL ALLOCATION Allocation Factor Pipeline	Allocation Factor Retail	Non-Jurisdictional Pipeline	Non-Jurisdictional Retail	Non-Jurisdictional Total	Jurisdictional	Total VNG	Percent Jurisdictional
	ACCUMULATED PROVISION FOR DEPRECIATION								
301-303	Intangible Plant		TPLANT		1,698,093	1,698,093	17,420,563	19,118,657	91.12%
304-364	Storage/Production Plant		DDIX'		471,868	471,868	3,787,698	4,259,566	88.92%
365-371	Transmission Plant*	XMSpec/PKAVO	PKAVO	5,807,978	2,031,869	7,839,847	79,161,607	87,001,454	90.99%
374-387	Distribution Plant	XMSpec/PKAVO	DISTPLT	141,919	24,549,507	24,691,426	247,869,163	272,560,588	90.94%
389-398	General Plant	XMSpec/PKAVO	PLANT	2,814	315,109	317,923	5,332,678	5,850,601	91.15%
							-	-	
-	TOTAL ACCUMULATED PROVISION FOR DEPRECIATION			5,952,711	29,266,447	35,219,157	353,571,710	388,790,867	90.94%
-	NET PLANT INVESTMENT			22,133,322	69,174,523	91,307,845	942,856,160	########	91.17%
	COST FREE CAPITAL DEDUCTIONS								
	ACCUMULATED DEFERRED INCOME TAXES (13mo Avg.)								
	Bad Debts		SALES	-	27,643	27,643	188,563	216,206	87.21%
	Book/Tax Difference Partnership Income		TPLANT	-	-	-	-	-	0.00%
	NSP		OMEXP	-	3,757	3,757	40,800	44,557	91.57%
	Misc./Deferred Reconciliation		TPLANT	-	16,290	16,290	167,122	183,413	91.12%
	Accrued Postretirement Benefits		OMEXP	-	(314,490)	(314,490)	(3,415,637)	(3,730,127)	91.57%
	Pension		OMEXP	-	1,124,833	1,124,833	12,216,663	13,341,496	91.57%
	Liberalized Depreciation	XMSpec.	PKAVO	(3,897,517)	(22,511,335)	(26,408,852)	(194,230,930)	(220,639,782)	88.03%
	Amortization Goodwill		PLANT	-	-	-	-	-	0.00%
	Deferred Purchased Gas Adjustment		GAS	-	(275,137)	(275,137)	(1,640,512)	(1,915,649)	85.64%
	CIAC and Customer Advances		DISTPLT	-	-	-	-	-	0.00%
	Engineering Costs		TPLANT	-	-	-	-	-	0.00%
	Removal Costs		TPLANT	-	-	-	-	-	0.00%
	Deductible G+A		OMEXP	-	-	-	-	-	0.00%
	Regulatory Amortization		TPLANT	-	-	-	-	-	0.00%
	Property State		PLANT	-	(2,607,459)	(2,607,459)	(26,749,083)	(29,356,542)	91.12%
	Environmental Response Cost		TPLANT	-	-	-	-	-	0.00%
	Leasehold Improvements		PLANT	-	41,731	41,731	428,105	469,836	91.12%
	Insurance reserve		TPLANT	-	2,303	2,303	23,624	25,927	91.12%
	Receipts Tax Adjustment		TPLANT	-	(1,334)	(1,334)	(13,690)	(15,024)	91.12%
	Stock Options		OMEXP	-	-	-	-	-	0.00%
	481(a) Deductible General & Administrative		OMEXP	-	(158,545)	(158,545)	(1,721,932)	(1,880,477)	91.57%
	Rate Case		TPLANT	-	-	-	-	-	0.00%
	Restricted Stock units		OMEXP	-	1,413	1,413	15,349	16,762	91.57%
	Interest and Taxes Charged to Contruction		CWIP	-	-	-	-	-	0.00%
	Accrued Bonus		OMEXP	-	5,797	5,797	62,957	68,754	91.57%
	Revenue Normalization Adj'mt		SALES	-	690	690	4,704	5,394	87.21%
	APIC/Over/under collections, Other		PLANT	-	(18,203)	(18,203)	(186,742)	(204,945)	91.12%
	TOTAL ACCUMULATED DEFERRED INCOME TAXES			(3,897,517)	(24,662,047)	(28,559,564)	(214,810,637)	(243,370,201)	88.26%
	Customer Advances for Construction		DISTPLT	-	-	-	-	-	0.00%
-	TOTAL COSTS FREE CAPITAL DEDUCTIONS			(3,897,517)	(24,662,047)	(28,559,564)	(214,810,637)	(243,370,201)	88.26%

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OAG Proposed
Virginia Natural Gas Company
Jurisdictional Cost Separation Study
Year Ended 09/30/16

FERC ACCT.	DETAIL OF RATE BASE As of 9/30/2016	TOTAL COSTS Total VNG GAAP Basis	HRX Equity Adjustments	Total VNG Regulatory Basis	PIPELINE COSTS OF SERVICE JUP-PT-1 pipeline Dept. 4082, 4009	HRX Pipeline Ladysmith Dept. 4018	Charles City Dept. 4017	pipeline Dept. 4018	Total HRX	VNG Lateral Dept. 4081	Yorktown Pipeline	Rock Tenn	TOTAL Pipeline	NET VNG Retail	JURISDICTIONAL ALLOCATION Allocation Factor Pipeline	Retail	Non-Jurisdictional Pipeline	Non-Jurisdictional Retail	Non-Jurisdictional Total	Jurisdictional	Total VNG	Percent Jurisdictional
	WORKING CAPITAL AND DEFERRED DEBITS & CREDITS																					
.	Materials and Supplies (13mo. Avg)	278,671		278,671					-					278,671		DISTPLT	-	25,384	25,384	253,286	278,671	90.89%
	Fuel Inventory (13 mo. Avg.)	19,418,644		19,418,644					-					19,418,644		DIHXC	-	2,151,168	2,151,168	17,267,475	19,418,644	88.92%
	Cash (lead-lag study)	34,412,224	24,883	34,437,107					-					34,437,107		OMEXP	-		2,929,324	31,507,783	34,437,107	91.49%
	Deferred Purch. Gas (13 mo. Avg.)	(4,063,568)		(4,063,568)					-					(4,063,568)		GAS	-	(583,635)	(583,635)	(3,479,934)	(4,063,568)	85.64%
	Less:													-								
	Customer Deposits end of period	14,334,306		14,334,306					-					14,334,306		SALES	-	1,832,688	1,832,688	12,501,618	14,334,306	87.21%
	Supplier Refunds (13 mo. Avg.)	325,305		325,305					-					325,305		SALES	-	41,591	41,591	283,714	325,305	87.21%
+	TOTAL WORKING CAP AND DEFERRED DEBITS & CREDITS	35,386,360	24,883	35,411,242	-	-	-	-	-	-	-	-	-	35,411,242			-	(281,361)	2,647,963	32,763,280	35,411,242	92.52%
									-													
=	RATE BASE, incl Acq. Adj'mt	815,080,428	11,124,618	826,205,046	31,464,543	#########	17,582,033	116,507,682	149,235,796	#########	-	12,141,787	291,650,120	609,268,562			18,235,805	44,231,114	65,396,243	760,808,803	826,205,046	92.08%
	Acquisition Adjustment (above)	165,293,601		165,293,601					-				(165,293,601)	165,293,601		PLANT		14,681,438	14,681,438	150,612,163	165,293,601	91.12%
	RATE BASE, excl Acq. Adj'mt	649,786,828	11,124,618	660,911,446	31,464,543	#########	17,582,033	116,507,682	149,235,796	#########	-	12,141,787	456,943,721	443,974,962			18,235,805	29,549,676	50,714,805	610,196,641	660,911,446	92.33%

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OAG Proposed
Virginia Natural Gas Company
Jurisdictional Cost Separation Study
Test Year Ended
9/30/2016

FERC ACCT	DETAIL OF OPERATING INCOME Year ending 9/30/2016	TOTAL COSTS: Total VNG GAAP Basis	TOTAL COSTS: HRX Equity Adj.+Alloc Dep	TOTAL COSTS: Total VNG Regulatory Basis	PIPELINE/TRANSM SERVICE: JLP/PT-1 pipeline Depts. 4012, 4509	HRX Pipeline: Ladysmith Dept. 4014	HRX Pipeline: Charles City Dept. 4017	HRX Pipeline: VNG pipeline Dept. 4018	HRX Total	VNG Lateral Dept. 4511	Yorktown pipeline	Rich Tenn	TOTAL Pipeline	NET VNG Retail	Allocation Factor: Pipeline	Allocation Factor: Retail	JURISDICTIONAL ALLOCATION: Non-Jurisdictional Pipeline	Non-Jurisdictional Retail	Non-Jurisdictional Total	Jurisdictional	Total VNG	Percent Jurisdictional
	OPERATING REVENUE																					
480	Residential Sales	146,766,630		146,766,630									-	146,766,630		DIR		327,213	327,213	146,439,417	146,766,630	99.78%
481/489	Commercial & Industrial Deliveries	66,892,212		66,892,212					-				-	66,892,212		DIR		21,535,469	21,535,469	45,356,743	66,892,212	67.81%
	SAVE	9,787,775	82,753	9,870,528					-				-	9,870,528		DIR		1,047,642	1,047,642	8,822,886	9,870,528	89.39%
	Gas Storage Carrying Charges	1,680,571		1,680,571					-				-	1,680,571		DIR		-	-	1,680,571	1,680,571	100.00%
487	Forfeited Discounts	943,489		943,489					-				-	943,489		DIR		123,843	123,843	819,645	943,489	86.87%
488	Miscellaneous Service Revenues	17,814		17,814					-				-	17,814		DIR		173	173	17,641	17,814	99.03%
	Damage Billing	231,694		231,694					-				-	231,694		DIR		10,124	10,124	221,569	231,694	95.63%
	PT-1/JLP Capacity Chg+ Contract reimburs	3,428,572		3,428,572	3,428,572				-				3,428,572	-		DIR		-	-	3,428,572	3,428,572	100.00%
	HRX	10,070,021		10,070,021					10,070,021				10,070,021	-		DIR		-	-	10,070,021	10,070,021	100.00%
	Reconnect/Turn On/meter set	1,637,553		1,637,553					-				-	1,637,553		DIR		15,898	15,898	1,621,655	1,637,553	99.03%
	TOTAL OPERATING REVENUE	241,456,330	82,753	241,539,084	3,428,572	-	-	-	10,070,021	-	-		13,498,593	228,040,491			-	23,060,363	23,060,363	218,478,721	241,539,084	90.45%
	OPERATION & MAINTENANCE EXPENSES								-													
	PRODUCTION EXPENSES								-													
750	Operation Supervision & Engineering								-				-	-							-	
834	Other	-		-					-				-	-		DDDC	-	-	-	-	-	0.00%
	TOTAL PRODUCTION EXPENSES	-	-	-	-	-	-	-	-	-	-	-	-	-			-	-	-	-	-	0.00%
	STORAGE & PROCESSING EXPENSES																					
821-834	Purification			-					-				-	-		DDDC			-	-	-	
840-841	Operation Labor and Expenses	175,148		175,148			1,761		1,761				1,761	173,387	XMSpec	DDDC	156	19,208	19,364	155,785	175,148	88.94%
817-843	Maintenance	52,965		52,965			-		-				-	52,965	XMSpec	DDDC	-	5,867	5,867	47,097	52,965	88.92%
	TOTAL STORAGE & PROCESSING EXPENSES	228,113	-	228,113	-	-	1,761	-	1,761	-	-	-	1,761	226,352			156	25,075	25,231	202,882	228,113	88.94%
	TOTAL PRODUCTION, STORAGE & PROCESSING EXPENSES	228,113	-	228,113	-	-	1,761	-	1,761	-	-	-	1,761	226,352			156	25,075	25,231	202,882	228,113	88.94%
	OTHER GAS SUPPLY EXPENSES																					
803-4	Gas Purchased Expenses	82,363,366		82,363,366					-				-	82,363,366		GAS	-	11,829,531	11,829,531	70,533,834	82,363,366	85.64%
808	Other Purchased Gas Expenses	-		-					-				-	-		DIR		-	-	-	-	0.00%
	TOTAL GAS SUPPLY EXPENSES	82,363,366	-	82,363,366	-	-	-	-	-	-	-	-	-	82,363,366				11,829,531	11,829,531	70,533,834	82,363,366	85.64%
	TRANSMISSION EXPENSES-OPERATION																					
850	Operation Supervision & Eng.	3,859	-	3,859	3,859				-	-			3,859	-	XMSpec	PKAVG	181	-	181	3,677	3,859	95.31%
856	Mains*	-	-	-					-				-	-		PKAVG	-	-	-	-	-	0.00%
857	Meas.+ Reg Expenses*	151	-	151					-				-	151		PKAVG	-	20	20	131	151	86.80%
	TOTAL TRANSMISSION EXPENSES-OPERATION	4,009	-	4,009	3,859	-	-	-	-	-	-	-	3,859	151			181	20	201	3,808	4,009	94.99%
	TRANSMISSION EXPENSES-MAINTENANCE	13	-	13	13			(16,250)	(16,250)				(16,237)	16,250	XMSpec	PKAVG	(1,539)	2,145	606	(593)	13	-4636.74%
	TOTAL TRANSMISSION EXPENSES-MAINTENANCE	13	-	13	13	-	-	(16,250)	(16,250)	-	-	-	(16,237)	16,250			(1,539)	2,145	606	(593)	13	-4636.74%
	TOTAL TRANSMISSION EXPENSES	4,022	-	4,022	3,872	-	-	(16,250)	(16,250)	-	-	-	(12,379)	16,401			(1,358)	2,165	807	3,215	4,022	79.94%
	DISTRIBUTION EXPENSES-OPERATIONS																					
870	Operation Supervision & Engineering	357		357					-				-	357		DISTPLT	-	33	33	325	357	90.89%
871	Load Dispatching	9,189		9,189					-				-	9,189		PKAVG	-	1,213	1,213	7,976	9,189	86.80%
872	Compressor Sta. Fuel and Power	-		-					-				-	-		DISTPLT	-	-	-	-	-	0.00%
874	Mains & Services	7,237,474		7,237,474	84,834				-				84,834	7,152,640	XMSpec	MSPLANT	2,724	646,086	648,810	6,588,664	7,237,474	91.04%
875/877	Measuring and Regulator Station	213,623		213,623	6,588				-				6,588	207,034	XMSpec	THRU	359	31,714	32,073	181,550	213,623	84.99%
878	Meter and House Regulator	1,009,992		1,009,992					-				-	1,009,992		WTMETER	-	68,818	68,818	941,174	1,009,992	93.19%
879	Customer Installation	1,428,976		1,428,976					-				-	1,428,976		CUST	-	14,583	14,583	1,414,393	1,428,976	98.98%
880	Other Expenses	273,002		273,002					-				-	273,002		DISTPLT	-	24,868	24,868	248,133	273,002	90.89%
881	Rent	-		-					-				-	-					-	-	-	0.00%
	TOTAL DISTRIBUTION EXPENSES-OPERATION	10,172,612	-	10,172,612	91,422	-	-	-	-	-	-	-	91,422	10,081,190			3,083	787,314	790,397	9,382,215	10,172,612	92.23%
	DISTRIBUTION EXPENSES-MAINTENANCE																					
885/886	Supervision & Engineering	42,782		42,782					-				-	42,782		DISTPLT	-	3,897	3,897	38,885	42,782	90.89%
887	Mains	6,493,172		6,493,172	953,280	4,439	6,429		10,867	4,873			969,020	5,524,147	XMSpec	PKAVG	46,276	729,079	775,355	5,717,817	6,493,172	88.06%
888	Maint. Compressor Sta. Equipment	395,156		395,156		157,323	153,573		310,896				310,896	84,260	XMSpec	THRU	30,433	12,907	43,340	351,816	395,156	89.03%
889/891	Measuring & Regulating Station Equipment	692,407		692,407	185,982	908			908	(238)			186,652	505,755	XMSpec	THRU	10,162	77,472	87,634	604,772	692,407	87.34%
892	Services	2,707,713		2,707,713					-				-	2,707,713		WTSERV	-	66,763	66,763	2,640,950	2,707,713	97.53%
893	Meters & House Regulators	1,431,118		1,431,118	(1,113)	51			51				(1,061)	1,432,179	XMSpec	WTMETER	(73)	97,592	97,519	1,333,599	1,431,118	93.18%
894	Other Equipment	200,172		200,172					-				-	200,172		DISTPLT	-	18,234	18,234	181,938	200,172	90.89%
	TOTAL DISTRIBUTION EXPENSES-MAINTENANCE	11,962,520	-	11,962,520	1,138,149	162,721	160,002	-	322,723	4,640	-	-	1,465,512	10,497,008			86,843	1,005,940	1,092,783	10,869,737	11,962,520	90.86%
	TOTAL DISTRIBUTION EXPENSES	22,135,132	-	22,135,132	1,229,571	162,721	160,002	-	322,723	4,640	-	-	1,556,935	20,578,198			89,926	1,793,254	1,883,180	20,251,952	22,135,132	91.49%

OAG Proposed
Virginia Natural Gas Company
Jurisdictional Cost Separation Study
Test Year Ended
9/30/2016

FERC ACCT.	DETAIL OF OPERATING INCOME Year ending 9/30/2016	TOTAL COSTS: Total VNG GAAP Basis	HRX Equity Adj.+Alloc.Dep	Total VNG Regulatory Basis	PIPELINE COSTS OF SERVICE: JUP/PT-1 pipeline Depts 4082, 4009	HRX Pipeline: Ladysmith Dept. 4018	Charles City Dept 4017	VNG pipeline Dept 4018	HRX Total	VNG Lateral Dept. 4081	Yorktown pipeline	Rock Tenn	TOTAL Pipeline	NET VNG Retail	JURISDICTIONAL ALLOCATION: Allocation Factor Pipeline	Allocation Factor Retail	Non-Jurisdictional Pipeline	Non-Jurisdictional Retail	Non-Jurisdictional Total	Jurisdictional	Total VNG	Percent Jurisdictional
	CUSTOMER ACCOUNTS EXPENSES																					
901	Supervision	-		-					-				-	-		WTMETER	-	-	-	-	-	
902	Meter Reading	379,829		379,829					-				-	379,829	XMSpec	CUST	-	3,876	3,876	375,953	379,829	98.98%
903	Customer Records & Collection	5,205		5,205		-			-				-	5,205		WTMETER	-	355	355	4,850	5,205	93.19%
904	Uncollectible Accounts	749,732		749,732					-				-	749,732		SALES	-	95,856	95,856	653,876	749,732	87.21%
905	Misc. Expenses	-		-					-				-	-		CUST	-	-	-	-	-	0.00%
	TOTAL CUSTOMER ACCOUNTS EXPENSES	1,134,765	-	1,134,765	-	-	-	-	-	-	-	-	-	1,134,765			-	100,086	100,086	1,034,679	1,134,765	91.18%
	CUSTOMER SERVICE AND INFO. EXPENSES																					
907	Supervision	-		-				-	-				-	-		CUST	-	-	-	-	-	0.00%
908/909	Customer Assistance	32,753		32,753					-				-	32,753		CUST	-	334	334	32,419	32,753	98.98%
	TOTAL CUSTOMER SERVICE AND INFO. EXPENSES	32,753	-	32,753	-	-	-	-	-	-	-	-	-	32,753			-	334	334	32,419	32,753	98.98%
	SALES EXPENSES																					
910/911	Supervision	14,415		14,415					-				-	14,415		CUST	-	147	147	14,268	14,415	98.98%
912	Demonstration and Selling	89,378		89,378					-				-	89,378		CUST	-	912	912	88,466	89,378	98.98%
913/916	Advertising/Misc.	238,755		238,755	1,610				-				1,610	237,144	XMSpec	CUST	6	2,414?	2,420	236,335	238,755	98.99%
	TOTAL SALES EXPENSE	342,548?	-	342,548?	1,610	-	-	-	-	-	-	-	1,610	340,937		-	6	3,473?	3,479	339,068	342,548	98.98%
	ADMINISTRATIVE AND GENERAL-OPERATION																					
920	Administrative and General Salaries	23,951,172		23,951,172	147,282				-	3,438			150,720	23,800,452	XMSpec	OMEXP	4,679	2,006,885?	2,011,564	21,939,608	23,951,172	91.60%
921	Office Supplies and Expenses	4,232,911		4,232,911	2,755	628,787?	209,067	382	838,236				840,991	3,391,920	XMSpec	OMEXP	39,754	285,976	325,735	3,907,177	4,232,911	92.30%
922	Administrative Expenses Transferred	(6,266,871)		(6,266,871)	(43,617)	(76)	(820)		(896)	(2,155)			(46,668)	(6,220,203)	XMSpec	OMEXP	(1,532)	(524,504)?	(526,036)	(5,740,836)	(6,266,871)	91.61%
923	Outside Services Employed	5,332,599		5,332,599	20,803	-	267		267				21,070	5,311,529	XMSpec	OMEXP	642	447,854?	448,496	4,884,103	5,332,599	91.59%
924	Property Insurance	610,077		610,077					-				-	610,077	XMSpec	PLANT	-	54,187	54,187	555,890	610,077	91.12%
925	Injuries and Damages	217,778		217,778					-				-	217,778		OMEXP	-	18,361	18,361	199,417	217,778	91.57%
926	Employee Pensions and Benefits	4,853,578		4,853,578	(15,438)				-	(4,148)			(19,585)	4,873,163	XMSpec	OMEXP	(782)	410,835?	410,053	4,443,526	4,853,578	91.55%
927/928	Franchise/Regulatory Commission Expenses	264		264					-				-	264		PLANT	-	23	23	240	264	91.12%
930.1	General Advertising Expense	-		-					-				-	-		CUST	-	-	-	-	-	0.00%
930.2	Miscellaneous and General	1,052,076		1,052,076		6,171	6,541		12,712				12,712	1,039,364	XMSpec	TPLANT	729	92,315	93,044	959,032	1,052,076	91.10%
931	Rents/Lease	871,891		871,891					-				-	871,891		TPLANT	-	77,440	77,440	794,451	871,891	91.12%
	TOTAL ADMINISTRATIVE & GENERAL-OPERATION	34,855,474	-	34,855,474	113,785	634,882	215,055	382	850,319	(2,864)	-		959,240	33,896,234			43,490	2,869,377?	2,912,867	31,942,607	34,855,474	91.64%
932	Maintenance of General Plant	2,204,586		2,204,586	12	18,561	26,647		45,209				45,221	2,159,365	XMSpec	TPLANT	2,688	191,792	194,480	2,010,106	2,204,586	91.18%
	TOTAL ADMINISTRATIVE & GENERAL-MAINTENANCE	2,204,586	-	2,204,586	12	18,561	26,647	-	45,209	-	-		45,221	2,159,365			2,688	191,792	194,480	2,010,106	2,204,586	91.18%
	TOTAL ADMINISTRATIVE & GENERAL	37,060,060	-	37,060,060	113,798	653,444	241,703	382	895,528	(2,864)	-	-	1,001,461	36,058,599?			46,179	3,061,168?	3,107,347	33,952,713	37,060,060	91.62%
	TOTAL OPERATION AND MAINTENANCE EXPENSES	143,300,759	-	143,300,759	1,346,851	816,164	403,466	(15,868)	1,203,761	1,776	-		2,552,388	140,748,371			134,911	16,814,903	16,949,997	126,350,762	143,300,759	88.17%
	DEPRECIATION AND AMORTIZATION EXPENSES																					
	Intangible Plant	855,441		855,441					-				-	855,441		PLANT	-	75,981	75,981	779,460	855,441	91.12%
	Production /Storage Plant	254,321		254,321					-				-	254,321		DDUC	-	28,173	28,173	226,148	254,321	88.92%
	Transmission Plant*	6,359,127	248,032	6,607,159	1,385,533	719,137	684,916	2,502,928	3,906,981	1,099,629	-	298,761	6,690,904	(83,745)	XMSpec	PKAVG	552,639	(11,053)	541,586	6,065,573	6,607,159	91.80%
	Distribution Plant	20,447,037	20,575	20,467,612				184	184				184	20,467,428		DISTPLT	12	1,864,405	1,864,417	18,603,195	20,467,612	90.89%
	General Plant	2,866,782		2,866,782		5,684	4,928		10,612				10,612	2,856,170		PLANT	593	253,686	254,280	2,612,502	2,866,782	91.13%
	TOTAL DEPRECIATION AND AMORTIZATION EXPENSES	30,782,709	268,607	31,051,316	1,385,533	724,821	689,845	2,503,112	3,917,778	1,099,629	-	298,761	6,701,701	24,349,615			553,244	2,211,192	2,764,436	28,286,879	31,051,316	91.10%
	TAXES OTHER THAN INCOME TAXES																					
	Payroll	997,646		997,646	(1,964)				-				(1,964)	999,610		OMEXP	(59)	84,278	84,219	913,427	997,646	91.56%
	Property Tax	6,737,313		6,737,313	363,695	148,775	145,120	946,684	1,240,579	255,029		122,838	1,982,140	4,755,173	XMSpec/RRDC	TPLANT	109,192	422,348	531,540	6,205,773	6,737,313	92.11%
	Other	688,985	4,290	693,275					-				-	693,275		OMEXP	-	58,451	58,451	634,824	693,275	91.57%
	TOTAL TAXES OTHER THAN INCOME TAXES	8,423,944	4,290	8,428,234	361,730	148,775	145,120	946,684	1,240,579	255,029	-	122,838	1,980,176	6,448,058			109,133	565,077	674,210	7,754,024	8,428,234	92.00%

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OAG Proposed
Virginia Natural Gas Company
Jurisdictional Cost Separation Study
Test Year Ended
9/30/2016

TOTAL COSTS

FERC ACCT.	DETAIL OF OPERATING INCOME Year ending 9/30/2016	Total VNG GAAP Basis	IRX Equity Adj.+Alloc.Dep	Total VNG Regulatory Basis
	OTHER INCOME/ EXPENSE ADJUSTMENTS			
	Loss on Property	(18,761)		(18,761)
	Interest on Customer Deposits			-
	Interest on Supplier Refunds			-
	AFUDC			-
	Other Income	1,214,403		1,214,403
	TOTAL OTHER INCOME/EXPENSE ADJUSTMENTS	1,195,642	-	1,195,642
	FEDERAL & STATE INCOME TAX COMPUTATION			
	Operating Income Before Federal Income Tax	60,144,561	(190,143)	59,954,417
	Less: Interest/Other Inc/Other Interest	18,822,171	19,205	18,641,376
	NET OPERATING INCOME-pre tax	41,322,390	(209,348)	41,313,041
	SCHEDULE M ADDITIONS TO OPERATING INCOME			
	Regional Greenhouse Gas Initiative	-		-
	CIAC	-		-
	Restricted and Stock Options	187,197		187,197
	Fines/penalties/meals/dues/bonus	17,900		17,900
	Leasehold Improvements/cowler/Fuchs	102,792		102,792
	Unamortized rate Case Expense/Lobby	94,964		94,964
	Pensions/OPEB/net PRB	(409,832)		(409,832)
	Bad Debts	357,365		357,365
	TOTAL ADDITIONS	350,336	-	350,336
	SCHEDULE M DEDUCTIONS FROM OPERATING INCOME			
	Depreciation/Amortization	(98,407,763)		(98,407,763)
	PGA	(4,924,548)		(4,924,548)
	Revenue Normalization Adjm't	138,292		138,292
	Over/Under Collections-Other	(182,910)		(182,910)
	Meals/Entertainment	9,308		9,308
	Energy Conserv. Program	(225,992)		(225,992)
	Insurance Reserve	8,879		8,879
	Misc./Performance Cash/Partnership Interest	48,291		48,291
	TOTAL DEDUCTIONS	(103,536,443)	-	(103,536,443)
	TAX INCOME	(61,863,717)	(209,348)	(61,873,066)
	Other addn's for SIT	45,389,091		45,389,091
	Exclude Equity Tax - Deferred from Current Tax Calculation	-		-
	State Taxable Income	(16,274,626)	(209,348)	(16,483,975)
	State Tax Calc.@ 6.0%	(976,478)	(12,561)	(989,038)
	Prior Year State Adjustment	5,400,091		5,400,091
	PUCHA/AGSC Alloc	-		-
	State Tax--Current Provision	4,423,613		4,411,053
	Federal Taxable Income	(60,687,240)	(196,788)	(60,884,027)
	Federal Tax Calc. @ 35.00%	(21,240,534)	(68,876)	(21,309,410)
	Prior Yr. Federal Adj'mt	(735,069)		(735,069)
	PUCHA/AGSC Alloc.	269,885		269,885
	Federal Tax--Current Provision	(21,705,718)		(21,774,594)
	TOTAL INCOME TAX--CURRENT	(17,282,105)		(17,363,541)
	Prior Yr. Adjustment's and Tax Allocations: Return True Up	-		-
	TOTAL CURRENT FEDERAL & STATE INCOME TAX	(17,282,105)		(17,363,541)

PIPELINE COSTS OF SERVICE

DETAIL OF OPERATING INCOME	JUP/PT-1 pipeline Depts 4012, 4009	IIRX Pipeline: Ladysmith Dept. 4018	IIRX Pipeline: Charles City Dept. 4017	IIRX Pipeline: VNG pipeline Dept. 4038	IIRX Total	VNG Lateral Dept. 4081	Yorktown pipeline	Rack Team	TOTAL Pipeline
Loss on Property					-				-
Interest on Customer Deposits					-				-
Interest on Supplier Refunds					-				-
AFUDC					-				-
Other Income					-				-
TOTAL OTHER INCOME/EXPENSE ADJUSTMENTS	-	-	-	-	-	-	-	-	-
NET OPERATING INCOME-pre tax	-	-	-	-	-	-	-	-	
TOTAL ADDITIONS	-	-	-	-	-	-	-	-	
TOTAL DEDUCTIONS		-	-	-	-	-	-		
State Taxable Income	-								
Federal Taxable Income	-								
TOTAL INCOME TAX--CURRENT	-	-	-	-	-	-	-		
TOTAL CURRENT FEDERAL & STATE INCOME TAX	-	-	-	-	-	-	-		

JURISDICTIONAL ALLOCATION

DETAIL OF OPERATING INCOME	NET VNG Retail	Allocation Factor Pipeline	Allocation Factor Retail	Non-Jurisdictional Pipeline	Non-Jurisdictional Retail	Non-Jurisdictional Total	Jurisdictional	Total VNG	Percent Jurisdictional
Loss on Property	(18,761)		DIR		(18,761)	(18,761)	-	(18,761)	0.00%
Interest on Customer Deposits	-		SALES	-	-	-	-	-	0.00%
Interest on Supplier Refunds	-		SALES	-	-	-	-	-	0.00%
AFUDC	-		CWIP	-	-	-	-	-	
Other Income	1,214,403		DIR		1,214,403	1,214,403	-	1,214,403	0.00%
TOTAL OTHER INCOME/EXPENSE ADJUSTMENTS	1,195,642			-	1,195,642	1,195,642	-	1,195,642	0.00%
FEDERAL & STATE INCOME TAX COMPUTATION	VNG TOTAL								
Operating Income Before Federal Income Tax	59,954,417					3,867,363	56,087,055	59,954,417	93.55%
Less: Interest/Other Inc/Other Interest	18,641,376		NTPLT			1,645,874	16,995,502	18,641,376	91.17%
NET OPERATING INCOME-pre tax	41,313,041					2,221,418	39,091,553	41,313,041	94.62%
Regional Greenhouse Gas Initiative	-		SALES			-	-	-	0.00%
CIAC	-		DISTPLT			-	-	-	0.00%
Restricted and Stock Options	187,197		OMEXP			15,783	171,414	187,197	91.57%
Fines/penalties/meals/dues/bonus	17,900		OMEXP			1,509	16,391	17,900	91.57%
Leasehold Improvements/cowler/Fuchs	102,792		TPLANT			9,130	93,662	102,792	91.12%
Unamortized rate Case Expense/Lobby	94,964		TPLANT			8,435	86,529	94,964	91.12%
Pensions/OPEB/net PRB	(409,832)		OMEXP			(34,557)	(375,325)	(409,832)	91.57%
Bad Debts	357,365		SALES			45,690	311,675	357,365	87.21%
TOTAL ADDITIONS	350,336					45,989	304,347	350,336	86.87%
Depreciation/Amortization	(98,407,763)		DPEXP			(8,761,046)	(89,646,717)	(98,407,763)	91.10%
PGA	(4,924,548)		PLANT			(437,400)	(4,487,148)	(4,924,548)	91.12%
Revenue Normalization Adjm't	138,292		OMEXP			11,660	126,632	138,292	91.57%
Over/Under Collections-Other	(182,910)		GAS			(26,271)	(156,639)	(182,910)	85.64%
Meals/Entertainment	9,308		TPLANT			827	8,481	9,308	91.12%
Energy Conserv. Program	(225,992)		SALES			(28,894)	(197,098)	(225,992)	87.21%
Insurance Reserve	8,879		CWIP			861	8,018	8,879	90.30%
Misc./Performance Cash/Partnership Interest	48,291		TPLANT			4,289	44,002	48,291	91.12%
TOTAL DEDUCTIONS	(103,536,443)				.	(9,235,974)	(94,300,469)	(103,536,443)	91.08%
TAX INCOME	(61,873,066)					(6,968,497)	(54,904,569)	(61,873,066)	88.74%
Other addn's for SIT	45,389,091		TPLANT			4,031,398	41,357,693	45,389,091	
Exclude Equity Tax - Deferred from Current Tax Calculation	-		TPLANT			-	-	-	
State Taxable Income	(16,483,975)					(2,937,099)	(13,546,876)	(16,483,975)	82.18%
State Tax Calc.@ 6.0%	(989,038)					(176,226)	(812,813)	(989,038)	82.18%
Prior Year State Adjustment	5,400,091						5,400,091	5,400,091	100.00%
PUCHA/AGSC Alloc	-								
State Tax--Current Provision	4,411,053					(176,226)	4,587,278	4,411,053	104.00%
Federal Taxable Income	(60,884,027)					(6,792,271)	(54,091,757)	(60,884,027)	88.84%
Federal Tax Calc. @ 35.00%	(21,309,410)					(2,377,295)	(18,932,115)	(21,309,410)	88.84%
Prior Yr. Federal Adj'mt	(735,069)		TPLANT			(65,288)	(669,781)	(735,069)	91.12%
PUCHA/AGSC Alloc.	269,885		TPLANT			23,971	245,914	269,885	91.12%
Federal Tax--Current Provision	(21,774,594)					(2,418,613)	(19,355,982)	(21,774,594)	88.89%
TOTAL INCOME TAX--CURRENT	(17,363,541)					(2,594,838)	(14,768,703)	(17,363,541)	85.06%
Prior Yr. Adjustment's and Tax Allocations: Return True Up	-					-	-	-	
TOTAL CURRENT FEDERAL & STATE INCOME TAX	(17,363,541)					(2,594,838)	(14,768,703)	(17,363,541)	85.06%

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OAG Proposed
Virginia Natural Gas Company
Jurisdictional Cost Separation Study
Test Year Ended
9/30/2016

FERC ACCT.	DETAIL OF OPERATING INCOME Year ending 9/30/2016	TOTAL COSTS Total VNG GAAP Basis	HRX Equity Adj.+Alloc.Dep	Total VNG Regulatory Basis	PIPELINE COSTS OF SERVICE AUP/PT-1 pipeline Depts. 4082, 4009	HRX Pipeline Ladysmith Dept. 4018	Charles City Dept. 4017	VNG pipeline Dept. 4038	HRX Total	VNG Lateral Dept. 4081	Yorktown pipeline	Rock Tenn	TOTAL Pipeline	NET VNG Retail	JURISDICTIONAL ALLOCATION Allocation Factor Pipeline	Allocation Factor Retail	Non-Jurisdictional Pipeline	Non-Jurisdictional Retail	Non-Jurisdictional Total	Jurisdictional	Total VNG	Percent Jurisdictional
	DEFERRED INCOME TAXES:																					
	Bad Debts	(139,015)		(139,015)										(139,015)		SALES		(17,774)	(17,774)	(121,241)	(139,015)	87.21%
	HRX Carrying cost charge	-	-	-										-		PKAVG		-	-	-	-	0.00%
		-	-	-										-		OMEXP		-	-	-	-	0.00%
		-		-										-		TPLANT		-	-	-	-	0.00%
	Accrued Postretirement Benefits	500,163		500,163										500,163		OMEXP		42,169	42,169	457,994	500,163	91.57%
	Pension-Other	(852,444)		(852,444)										(852,444)		OMEXP		(71,870)	(71,870)	(780,574)	(852,444)	91.57%
	Federal Depreciation	37,146,389		37,146,389	-	185,510	185,748	1,795,667	2,166,924	-				37,146,389		TPLANT		3,299,292	3,299,292	33,847,097	37,146,389	91.12%
	Amortization Goodwill	-		-										-		PLANT		-	-	-	-	0.00%
	Deferred Purchased Gas Adjustment	1,915,649		1,915,649										1,915,649		GAS		275,137	275,137	1,640,512	1,915,649	85.64%
	CIAC and Customer Advances	-		-										-		DISTPLT		-	-	-	-	0.00%
	Engineering Costs	-		-										-		TPLANT		-	-	-	-	0.00%
	Removal Costs	-		-										-		TPLANT		-	-	-	-	0.00%
	Deductible General & Administrative	-		-										-		OMEXP		-	-	-	-	0.00%
	Interest and Taxes Charged to Construction	-		-										-		TPLANT		-	-	-	-	0.00%
	Performance cash	(18,785)		(18,785)										(18,785)		TPLANT		(1,668)	(1,668)	(17,117)	(18,785)	91.12%
	Environmental Response Cost	-		-										-		TPLANT		-	-	-	-	0.00%
	Leasehold Improvements	(39,986)		(39,986)										(39,986)		TPLANT		(3,552)	(3,552)	(36,435)	(39,986)	91.12%
	Relocation Costs	-		-										-		DISTPLT		-	-	-	-	0.00%
	Insurance Reserves	(3,454)		(3,454)										(3,454)		TPLANT		(307)	(307)	(3,147)	(3,454)	91.12%
	Stock Options/Restricted stock	(144,330)		(144,330)										(144,330)		OMEXP		(12,169)	(12,169)	(132,162)	(144,330)	91.57%
	481(a) Deductible General & Administrative	-		-										-		OMEXP		-	-	-	-	0.00%
	Rate Case	-		-										-		TPLANT		-	-	-	-	0.00%
	Restricted Stock/ units	-		-										-		OMEXP		-	-	-	-	0.00%
	Over/Under Collections/rev normalization	65,758		65,758										65,758		SALES		8,407	8,407	57,351	65,758	87.21%
	Restricted stock units	71,511		71,511										71,511		OMEXP		6,029	6,029	65,482	71,511	91.57%
	Incentive Program-Energy Conservation	87,911		87,911										87,911		SALES		11,240	11,240	76,671	87,911	87.21%
	Accrued Bonus/Severance	511,726		511,726										511,726		OMEXP		43,144	43,144	468,582	511,726	91.57%
	Gain/Loss Difference			-					-					-		TPLANT		-	-	-	-	0.00%
	TOTAL INCOME TAXES DEFERRED	39,101,092	-	39,101,092	-	185,510	185,748	1,795,667	2,166,924	-	-	-	-	39,101,092			-	3,578,080	3,578,080	35,523,012	39,101,092	90.85%
	Adjustment to Def'd Tax Reserve-Accrued Carrying Charges								-					-		HRXPLT		-	-	-	-	0.00%
	TOTAL INCOME TAXES	21,818,987	(81,437)	21,737,551	-	185,510	185,748	1,795,667	2,166,924	-	-	-		21,737,551			-	3,578,080	983,242	20,754,309	21,737,551	95.48%
	TOTAL OPERATING EXPENSES AND TAXES	205,522,041	191,460	205,713,502										205,713,502					22,567,527	183,145,975	205,713,502	89.03%
	OTHER INCOME																					
	Other Income (above)	1,176,881	-	1,176,881	-	-	-	-	-	-	-			1,176,881		DIR			1,176,881		1,176,881	0.00%
	OTHER INCOME Adjustment	1,176,881	-	1,176,881	-	-	-	-	-	-	-	-	-	-					1,176,881	-	1,176,881	0.00%
	ADJUSTED OPERATING INCOME	37,111,170	(108,707)	37,002,463	3,428,372	-	-	-	10,170,021	-	-	-	11,498,593	22,326,989			-	21,060,163	1,669,717	35,332,746	37,002,463	95.49%

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Schedule GAW-4

Jurisdiction Revenue Requirement Impact of OAG Jurisdictional Cost Study

170820189

Virginia Natural Gas, Inc.
Rate of Return Statement Reflecting OAG Jurisdictional Separations
For the Test Year Ended 9/30/2016 and Rate Year Ended 8/31/2018
Case No. PUE-2016-00143

Line No.		(1) Virginia Jurisdictional Cost of Service	(2) Ratemaking Adjustments	(3) Virginia Jurisdictional Cost of Service After Adjustments (1) + (2)	(4) Revenue Requirement for a –% ROE	(5) Amounts After Revenue Requirement (3) + (4)
1	**Operating Revenues**					
2	Base Rate Revenues	107,398,801	12,576,954	119,975,755	15,961,300	135,937,055
3	Fuel Revenues	70,533,834	19,712,563	90,246,398	-	90,246,398
4	Late Payment Fees	819,645	23,031	842,677	-	842,677
5	SAVE Revenues	8,822,887	4,585,395	13,408,281	-	13,408,281
6	CARE/RNA Revenues	33,678	(33,678)	-	-	-
7	Weather Normalization Adjustment	13,829,847	(13,829,847)	-	-	-
8	Other Operating Revenues	17,040,029	(2,040,011)	15,000,018	-	15,000,018
9	**Total Operating Revenues**	218,478,721	20,994,408	239,473,129	15,961,300	255,434,429
10	**Operating Revenue Deductions**					
11	Operations & Maintenance Expense	126,350,762	21,391,202	147,741,964	81,403	147,823,367
12	Depreciation & Amortization	28,286,879	5,480,313	33,767,192	-	33,767,192
13	State & Federal Income Taxes	20,754,309	(6,881,201)	13,873,108	6,177,280	20,050,388
14	Taxes Other Than Income Taxes	7,754,024	992,874	8,746,898	-	8,746,898
15	(Gain)/Loss on Disposition of Property	-	-	-	-	-
16	**Total Operating Revenue Deductions**	183,145,974	20,983,188	204,129,162	6,258,683	210,387,845
17	**Operating Income**	35,332,747	11,220	35,343,967	9,702,617	45,046,584
18	Plus: AFUDC	-	-	-	-	-
19	Less: Charitable Donations	-	-	-	-	-
20	Interest Expense on Customer Deposits	45,873	3,827	49,701	-	49,701
21	Interest Expense on Supplier Refunds	22,420	(13,129)	9,291	-	9,291
22	**Adjusted Operating Income**	35,264,454	20,522	35,284,976	9,702,617	44,987,593
23	Plus: Other Income/(Expense)	-		-		-
24	Less: Interest Expense	16,923,953	(3,135,223)	13,788,730		13,788,730
25	Preferred Dividends	-		-		-
26	JDC Capital Expense	-	-	-		-
27	**Income Available For Common Equity**	18,340,501	3,155,744	21,496,246	9,702,617	31,198,863
28	Allowance for working Capital	45,548,610	1,908,944	47,457,554	-	47,457,554
29	Plus: Net Utility Plant	792,243,998	9,696,830	801,940,828	-	801,940,828
30	Less: Other Rate Base Deductions	227,595,969	(2,350,793)	225,245,176	-	225,245,176
31	**Total Rate Base**	610,196,639	13,956,568	624,153,207	-	624,153,207
32	Total Capital	610,196,639	13,956,568	624,153,207	-	624,153,207
33	Common Equity Capital	297,572,892	6,806,161	304,379,052	-	304,379,052
34	% Rate of Return Earned on Rate Base	5.78%	N/A	5.65%	N/A	7.20778%
35	% Rate of Return Earned on Common Equity	6.16%	N/A	7.06%	N/A	10.25%
36	% Equity Return Authorized			10.00%		10.25%

Virginia Natural Gas, Inc.
OAG Rate Base Statement - Per Books
For the Test Year Ended 9/30/2016
Case No. PUE-2016-00143

Line No.		(1) Total Company (GAAP)	(2) HRX / SAVE Equity Adjustments	(3) Virginia Regulatory Books (1) + (2)	(4) Non-Jurisdictional	(5) Virginia Cost of Service Amount	(6) Retail Transmission	(7) Retail Generation	(8) Retail Distribution	(9) Virginia Jurisdictional Gen. and Distr. Cost of Service (7) + (8)
1	ALLOWANCE FOR WORKING CAPITAL (13 Month Average)									
2	Material and Supplies	278,671	-	278,671	15,322	263,348	-	-	263,348	263,348
3	Cash Working Capital (Including Lead/Lag Study)	34,412,224	24,883	34,437,107	2,883,765	31,553,342	-	-	31,553,342	31,553,342
4	Deferred PGA - Credit Balance	(4,063,568)	-	(4,063,568)	(583,635)	(3,479,934)	-	-	(3,479,934)	(3,479,934)
5	Fuel Inventory	19,418,644	-	19,418,644	2,151,168	17,267,475	-	-	17,267,475	17,267,475
6	TOTAL ALLOWANCE FOR WORKING CAPITAL	50,045,971	24,883	50,070,853	4,466,621	45,604,232	-	-	45,604,232	45,604,232
7	NET UTILITY PLANT (End of Period)									
8	Utility Plant in Service	1,228,013,892	12,339,895	1,240,353,787	73,802,239	1,166,551,548	-	-	1,166,551,548	1,166,551,548
9	Acquisition Adjustment (1)	165,293,601	-	165,293,601	165,293,601	-	-	-	-	-
10	Construction Work in Progress	17,307,484	-	17,307,484	1,012,450	16,295,034	-	-	16,295,034	16,295,034
11	Plant Held for Future Use	-	-	-	-	-	-	-	-	-
12	Less: Accumulated Provision for Depreciation and Amortization	387,550,707	1,240,160	388,790,867	21,769,394	367,021,473	-	-	367,021,473	367,021,473
13	Customer Advances for Construction	-	-	-	-	-	-	-	-	-
14	TOTAL NET UTILITY PLANT	1,023,064,270	11,099,735	1,034,164,005	218,338,896	815,825,109	-	-	815,825,109	815,825,109
15	RATE BASE DEDUCTIONS									
16	Customer Deposits (13 Month Average)	14,334,306	-	14,334,306	1,832,688	12,501,618	-	-	12,501,618	12,501,618
17	Supplier Refunds (13 Month Average)	325,305	-	325,305	41,591	283,714	-	-	283,714	283,714
18	Accumulated Deferred Income Taxes									
19	Bad Debts	(216,206)	-	(216,206)	(27,643)	(188,563)	-	-	(188,563)	(188,563)
20	Book/Tax Difference Partnership Income	-	-	-	-	-	-	-	-	-
21	NSP	(44,557)	-	(44,557)	(2,475)	(42,082)	-	-	(42,082)	(42,082)
22	Deferred Reconciliation	(183,413)	-	(183,413)	(10,913)	(172,499)	-	-	(172,499)	(172,499)
23	Accrued Postretirement Benefits	3,730,127	-	3,730,127	207,185	3,522,942	-	-	3,522,942	3,522,942
24	Purchased Gas Adjustment	1,915,649	-	1,915,649	275,137	1,640,512	-	-	1,640,512	1,640,512
25	Pension	(13,341,496)	-	(13,341,496)	(741,035)	(12,600,461)	-	-	(12,600,461)	(12,600,461)
26	Liberalized Depreciation	220,639,782	-	220,639,782	22,166,410	198,473,372	-	-	198,473,372	198,473,372
27	Amortization Goodwill	-	-	-	-	-	-	-	-	-
28	CIAC and Customer Advances	-	-	-	-	-	-	-	-	-
29	Engineering Costs	-	-	-	-	-	-	-	-	-
30	Removal Costs	-	-	-	-	-	-	-	-	-
31	Deductible General & Administrative	-	-	-	-	-	-	-	-	-
32	Regulatory Amortization	-	-	-	-	-	-	-	-	-
33	Property State	29,356,542	-	29,356,542	1,746,745	27,609,797	-	-	27,609,797	27,609,797
34	Environmental Response Cost	-	-	-	-	-	-	-	-	-
35	Leasehold Improvements	(469,836)	-	(469,836)	(27,956)	(441,880)	-	-	(441,880)	(441,880)
36	Relocation Costs	-	-	-	-	-	-	-	-	-
37	Receipts Tax Adjustment	15,024	-	15,024	894	14,130	-	-	14,130	14,130
38	Stock Options	-	-	-	-	-	-	-	-	-
39	481(a) Deductible General & Administrative	1,880,477	-	1,880,477	104,449	1,776,028	-	-	1,776,028	1,776,028
40	Rate Case	-	-	-	-	-	-	-	-	-
41	Restricted Stock units	(16,762)	-	(16,762)	(931)	(15,831)	-	-	(15,831)	(15,831)
42	Revenue Normalization Adjustment	(5,394)	-	(5,394)	(690)	(4,704)	-	-	(4,704)	(4,704)
43	Interest and Taxes Charged to Contruction	-	-	-	-	-	-	-	-	-
44	Salaries Overhead G&A	-	-	-	-	-	-	-	-	-
45	Incentive Program-Energy Conservation	-	-	-	-	-	-	-	-	-
46	Additional Paid In Capital	-	-	-	-	-	-	-	-	-
47	Accrued Bonus	(68,754)	-	(68,754)	(3,819)	(64,935)	-	-	(64,935)	(64,935)
48	Credit Reserve	-	-	-	-	-	-	-	-	-
49	Insurance Reserve	(25,927)	-	(25,927)	(1,543)	(24,384)	-	-	(24,384)	(24,384)
50	SAVE Unrecovered Costs	204,945	-	204,945	12,194	192,751	-	-	192,751	192,751
51	Accrued Carrying Charges	-	-	-	-	-	-	-	-	-
52	AGL Services Company	-	-	-	-	-	-	-	-	-
53	Total Deferred Income Taxes	243,370,201	-	243,370,201	23,696,010	219,674,191	-	-	219,674,191	219,674,191
54	Other Cost Free Capital	-	-	-	-	-	-	-	-	-
55	TOTAL RATE BASE DEDUCTIONS	258,029,812	-	258,029,812	25,570,290	232,459,522	-	-	232,459,522	232,459,522
56	TOTAL RATE BASE	815,080,428	11,124,618	826,205,046	197,235,227	628,969,819	-	-	628,969,819	628,969,819

(1) The acquisition adjustment reflected above relates to AGL's acquisition of Virginia Natural Gas, Inc. and does not include any acquisition adjustments related to Southern Company's acquisition of AGLR.

Virginia Natural Gas, Inc.
Rate Base Statement -- OAG Ratemaking Adjustments
For the Test Year Ended 9/30/2016 and Rate Year Ended 8/31/2018
Case No. PUE-2016-00143

Line No.		(1) Virginia Jurisdictional Cost of Service	(2) Ratemaking Adjustments	(3) Virginia Jurisdictional Cost of Service After Adjustments
1	ALLOWANCE FOR WORKING CAPITAL (13 Month Average)			
2	Material and Supplies	263,348	(7,486)	255,863
3	Cash Working Capital (Including Lead/Lag Study)	31,553,342	15,703,972	47,257,314
4	Deferred PGA - Credit Balance	(3,479,934)	3,479,934	-
5	Fuel Inventory	17,267,475	(17,267,475)	-
6	TOTAL ALLOWANCE FOR WORKING CAPITAL	45,604,232	1,908,944	47,513,176
7	NET UTILITY PLANT			
8	Utility Plant in Service	1,166,551,548	12,785,638	1,179,337,186
9	Acquisition Adjustment	-	-	-
10	Construction Work in Progress	16,295,034	198,289	16,493,323
11	Plant Held for Future Use	-	-	-
12	Less: Accumulated Provision for Depreciation and Amortization	367,021,473	3,287,097	370,308,569
13	Customer Advances for Construction	-	-	-
14	TOTAL NET UTILITY PLANT	815,825,109	9,696,830	825,521,939
15	RATE BASE DEDUCTIONS			
16	Customer Deposits (13 Month Average)	12,501,618	(76,483)	12,425,134
17	Supplier Refunds (13 Month Average)	283,714	(167,577)	116,136
18	Accumulated Deferred Income Taxes			
19	Bad Debts	(188,563)	-	(188,563)
20	Book/Tax Difference Partnership Income	-	-	-
21	NSP	(42,082)	-	(42,082)
22	Deferred Reconciliation	(172,499)	172,499	-
23	Accrued Postretirement Benefits	3,522,942	2,158,187	5,681,130
24	Purchased Gas Adjustment	1,640,512	(1,640,512)	-
25	Pension	(12,600,461)	20,666,174	8,065,713
26	Liberalized Depreciation	198,473,372	(23,695,422)	174,777,951
27	Amortization Goodwill	-	-	-
28	CIAC and Customer Advances	-	-	-
29	Engineering Costs	-	-	-
30	Removal Costs	-	-	-
31	Deductible General & Administrative	-	-	-
32	Regulatory Amortization	-	-	-
33	Property State	27,609,797	(7,092,859)	20,516,938
34	Environmental Response Cost	-	-	-
35	Leasehold Improvements	(441,880)	(53,276)	(495,157)
36	Relocation Costs	-	-	-
37	Receipts Tax Adjustment	14,130	-	14,130
38	Stock Options	-	-	-
39	481(a) Deductible General & Administrative	1,776,028	-	1,776,028
40	Rate Case	-	399,587	399,587
41	Restricted Stock units	(15,831)	-	(15,831)
42	Revenue Normalization Adjustment	(4,704)	4,704	-
43	Interest and Taxes Charged to Contruction	-	-	-
44	Salaries Overhead G&A	-	-	-
45	Incentive Program-Energy Conservation	-	-	-
46	Additional Paid in Capital	-	-	-
47	Accrued Bonus	(64,935)	-	(64,935)
48	Credit Reserve	-	-	-
49	Insurance Reserve	(24,384)	-	(24,384)
50	SAVE Unrecovered Costs	192,751	(192,751)	-
51	Accrued Carrying Charges	-	2,077,675	2,077,675
52	AGL Services Company	-	5,089,259	5,089,259
53	Total Deferred Income Taxes	219,674,191	(2,106,733)	217,567,458
54	Other Cost Free Capital	-	-	-
55	TOTAL RATE BASE DEDUCTIONS	232,459,522	(2,350,793)	230,108,729
56	TOTAL RATE BASE	628,969,819	13,956,568	642,926,387

(1) The acquisition adjustment reflected above relates to AGL's acquisition of Virginia Natural Gas, Inc. and does not include any acquisition adjustments related to Southern Company's acquisition of AGLR.

Virginia Natural Gas, Inc.
Detail of OAG Ratemaking Adjustments - Rate Year Adjustments
For the Rate Year Ended 8/31/2018
Case No. PUE-2016-00143

Line No.		(1) Total Company	(2) Non-Jurisdiction	(3) Virginia Jurisdiction	(4) Non-Jurisdiction %
	Income Adjustments - Reflected in Column (2) of Schedule 21				
	A. OPERATING REVENUE ADJUSTMENTS				
1	Adjust Base Rate Revenues to Rate Year	11,749,397	(827,557)	12,576,954	
2	Adjust Fuel Revenues to Rate Year	22,503,347	2,790,783	19,712,563	
3	Adjust Late Payment Fees to Rate Year	26,511	3,480	23,031	
4	Adjust SAVE Revenues to Rate Year	4,242,537	(342,858)	4,585,395	
5	Adjust CARE/RNA Revenues to Rate Year	(33,678)		(33,678)	
6	Adjust Weather Normalization Adjustment Revenues to Rate Year	(13,829,847)		(13,829,847)	
7	Adjust Other Operating Revenues to Rate Year	(354,434)	5,006	(359,440)	
8	Eliminate Gas Storage Carrying Cost	(1,680,571)		(1,680,571)	
	Total Operating Revenue Adjustments	22,623,263	1,628,854	20,994,408	
	B. GAS COST ADJUSTMENTS				
9	Adjust Gas Costs to Rate Year	22,503,347	2,790,783	19,712,563	
	Total Gas Costs Adjustments	22,503,347	2,790,783	19,712,563	
	C. OPERATION AND MAINTENANCE EXPENSE ADJUSTMENTS				
10	Adjust Payroll to Rate Year	1,153,479	96,892	1,056,587	8.40%
11	Adjust Customer Accounts (Bad Debt) Expenses to Rate Year	64,607	5,427	59,180	8.40%
12	Adjust 401K Benefits to Rate Year	70,358	5,910	64,448	8.40%
13	Adjust Health Benefits to Rate Year	866,498	72,786	793,712	8.40%
14	Adjust Other Benefits to Rate Year	(78,147)	(6,564)	(71,583)	8.40%
15	Adjust Pension Benefits to Rate Year	1,278,627	107,405	1,171,222	8.40%
16	Adjust Other Post Retirement Benefits to Rate Year	(161,881)	(13,598)	(148,283)	8.40%
17	Adjust Outside Services Expense to Rate Year	124,218	10,434	113,783	8.40%
18	Adjust Other Operation and Maintenance expenses to Rate Year	378,608	31,803	346,804	8.40%
19	Adjust Capitalized Expenses to Rate Year	(1,170,124)	(98,290)	(1,071,834)	8.40%
20	Adjust Intercompany Billings and Allocated Costs to Rate Year	(693,666)	(58,268)	(635,398)	8.40%
	Total Operation and Maintenance Expense Adjustments	1,832,575	153,936	1,678,639	
	D. Depreciation and Amortization Expense Adjustments				
21	Adjust Depreciation and Amortization Expenses to Rate Yea	4,324,788	384,906	3,939,882	8.90%
22	Adjust Depreciation Expenses from Services Company to Rate Year	1,690,923	150,492	1,540,431	8.90%
	Total Depreciation and Amortization Expense Adjustments	6,015,711	535,398	5,480,313	
	E. CURRENT INCOME TAX ADJUSTMENTS				
23	Income Tax Effect of the Total Adjustments Under Section A "Revenues	8,800,449	633,624	8,166,825	
24	Income Tax Effect of the Total Adjustments Under Sections B & C "O&M"	(9,466,674)	(1,145,496)	(8,321,178)	
25	Income Tax Effect of the Total Adjustments Under Section D "Depreciation and Amortization	(2,340,112)	(208,270)	(2,131,842)	
26	Income Tax Effect of the Total Adjustments Under Section G "Taxes other than Income Taxes	(419,813)	(33,585)	(386,228)	
27	Income Tax Effect of the Total Adjustments Under Section H "Customer Deposits and Supplier Refunds	4,149	530	3,618	
28	Adjust Income Taxes for Interest Synchronization	1,219,602	-	1,219,602	
29	Adjust to Statutory Tax Rate and Record Deferred Income Taxes			11,072,650	
	Total Current Income Tax Adjustments	(2,202,399)	(753,196)	9,623,447	
	F. DEFERRED INCOME TAX ADJUSTMENTS				
30	Adjust to Statutory Tax Rate and Record Deferred Income Taxes			(16,619,782)	
	Total Deferred Income Tax Adjustments	-	-	(16,619,782)	
	G. TAXES OTHER THAN INCOME ADJUSTMENTS				
31	Adjust Property Taxes to Rate Year	1,007,044	80,564	926,481	8.00%
32	Adjust Payroll Taxes to Rate Year	63,811	5,105	58,706	8.00%
33	Adjust Allocated Taxes Other than Income from Services Company to Rate Year	8,356	668	7,687	8.00%
	Total Taxes Other Than Income Adjustments	1,079,211	86,337	992,874	
	H. INTEREST EXPENSE ADJUSTMENTS				
34	Adjust Interest Expense on Customer Deposits to Rate Year	4,388	561	3,827	12.79%
35	Adjust Interest Expense on Supplier Refunds to Rate Year	(15,053)	(1,925)	(13,129)	12.79%
36	Adjust Interest Expense Based on Proposed Weighted Cost of Capital for Ratemaking Purposes	(3,135,223)	-	(3,135,223)	
	Total Interest Expense Adjustments	(3,145,887)	(1,364)	(3,144,524)	
	I. JDC CAPITAL EXPENSE ADJUSTMENTS				
37	Adjust JDC Expense Based on VNG's Capital Structure for Ratemaking Purposes	-	-	-	
	Total JDC Expense Adjustments	-	-	-	

Virginia Natural Gas, Inc.
Detail of OAG Ratemaking Adjustments - Rate Year Adjustments
For the Rate Year Ended 8/31/2018
Case No. PUE-2016-00143

Line No.		(1) Total Company	(2) Non-Jurisdiction	(3) Virginia Jurisdiction	(4) Non-Jurisdiction %
	Rate Base Adjustments - Reflected in Column (2) of Schedule 24				
	J. ALLOWANCE FOR WORKING CAPITAL ADJUSTMENTS				
38	Adjust Material and Supplies to Rate Year	(8,236)	(750)	(7,486)	9.11%
39	Adjust Cash Working Capital Based on Lead-Lag Study to Rate Year	(114,174)	-	(114,174)	
40	Adjust Other Cash Working Capital to Rate Year	16,747,189	929,044	15,818,145	
41	Eliminate Deferred PGA Balance from Rate Year	4,063,568	583,635	3,479,934	14.36%
42	Eliminate Fuel Inventory balance from Rate Year	(19,418,644)	(2,151,168)	(17,267,475)	11.08%
	Total Working Capital Adjustments	1,269,704	(639,240)	1,908,944	
	K. Plant and CWIP Adjustments				
43	Adjust Plant to Rate Year	143,982,413	131,196,775	12,785,638	
44	Adjust CWIP to Rate Year	2,044,212	119,582	198,289	5.85%
	Total Plant and CWIP Adjustments	146,026,625	131,316,357	12,983,927	
	L. ACCUMULATED DEPRECIATION AND AMORTIZATION ADJUSTMENTS				
45	Adjust Accumulated Depreciation to Rate Year	36,281,419	32,994,322	3,287,097	
	Total Accumulated Depreciation and Amortization Adjustments	36,281,419	32,994,322	3,287,097	
	M. OTHER RATE BASE DEDUCTIONS ADJUSTMENTS				
46	Adjust Customer Deposits to Rate Year	(87,696)	(11,212)	(76,483)	12.79%
47	Adjust Supplier Refunds to Rate Year	(192,144)	(24,566)	(167,577)	12.79%
48	Adjust Deferred Income Taxes to Rate Year			(2,106,733)	
	Total Other Rate Base Deductions Adjustments	(279,839)	(35,778)	(2,350,793)	
	N. COMMON EQUITY CAPITAL				
49	Adjust Common Equity Capital to Reflect VNG's Capital Structure	6,806,161	-	6,806,161	

Virginia Natural Gas, Inc.
OAG Lead/Lag Cash Working Capital Calculation - Total Company (GAAP)
For the Test Year Ended 9/30/2016
Case No. PUE-2016-00143
Support for Column (1) of Schedule 22

Line No.		(1) Total Company Per Books Amounts	(2) Average Daily Amount	(3) Expense (Lead)/Lag Days	(4) Revenue Lag	(5) Net (Lead)/Lag Days	(6) Working Capital (Provided)/ Required
	Operating Expenses						
1	Purchased Gas Expense	82,363,366	225,653	(31.3)	49.5	18.2	4,099,821
2	OPEB Expense	(382,550)	(1,048)	-	49.5	49.5	(51,849)
3	Pension Expense	2,191,373	6,004	-	49.5	49.5	297,007
4	Payroll Expense	18,248,462	49,996	(34.8)	49.5	14.7	734,563
5	Health Benefits Expense	1,775,239	4,864	(11.0)	49.5	38.5	187,170
6	Other Benefits Expense	89,619	246	(12.1)	49.5	37.3	9,165
7	Uncollectible Expense	749,732	2,054	(49.5)	49.5	0.0	-
8	401K Benefits Expense	869,316	2,382	(11.1)	49.5	38.4	91,402
9	Allocations From Services Company	18,846,106	51,633	(21.6)	49.5	27.9	1,439,117
10	Other O&M Expenses	18,550,097	50,822	(40.3)	49.5	9.2	465,646
11	Depreciation and Amortization Expense	30,782,709	84,336	-	49.5	49.5	4,172,120
12	Federal Income Taxes (Current)	(16,305,626)	(44,673)	(38.0)	49.5	11.5	(512,403)
13	Federal Income Taxes (Deferred)	35,625,940	97,605	-	49.5	49.5	4,828,545
14	State Income Tax (Current)	(976,478)	(2,675)	(38.0)	49.5	11.5	(30,686)
15	State Income Tax (Deferred)	3,475,151	9,521	-	49.5	49.5	471,003
16	Property Tax	7,426,298	20,346	(107.4)	49.5	(57.9)	(1,178,758)
17	Payroll Tax	997,646	2,733	(15.8)	49.5	33.7	92,136
18	AFUDC	-	-	(49.5)	49.5	0.0	-
19	Charitable Donations	-	-	(49.5)	49.5	0.0	-
20	Interest on Customer Deposits	52,598	144	(182.5)	49.5	(133.0)	(19,170)
21	Interest on Supplier Refunds	25,706	70	(182.5)	49.5	(133.0)	(9,369)
22	Other Expense/Income	1,214,404	3,327	(49.5)	49.5	0.0	-
23	LT Interest Expense	18,543,867	50,805	(45.8)	49.5	3.7	188,976
24	ST Interest Expense	-	-	-	49.5	49.5	-
25	JDC Expense	-	-	(49.5)	49.5	0.0	-
26	Income Available for Common Equity	19,703,401	53,982	(49.5)	49.5	0.0	-
27	**Totals**	**243,866,377**	**668,127**				**15,274,435**
	Plus:						
28	State Withholding Taxes	1,100,588	3,015	(14.7)	49.5	34.7	104,717
29	Federal Withholding Taxes	3,314,431	9,081	(14.7)	49.5	34.7	315,432
30	State Consumption Tax	2,498,746	6,846	(52.2)	49.5	(2.7)	(18,564)
31	Local Consumption Tax	661,660	1,813	(52.2)	49.5	(2.7)	(4,916)
32	Customer Utility Tax	11,409,037	31,258	(52.2)	49.5	(2.7)	(85,179)
33	Federal Excise Tax	-	-	(69.8)	49.5	(20.3)	-
34	Motor Fuel Tax	22,207	61	(65.1)	49.5	(15.6)	(949)
35	Sales and Use Tax	101,408	278	(32.1)	49.5	17.4	4,825
36	**Cash Working Capital (Lead/Lag)**						**15,589,800**
37	**BALANCE SHEET ITEMS (Schedule 28)**						18,822,424
38	**TOTAL CASH WORKING CAPITAL**						**34,412,224**

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Virginia Natural Gas, Inc.
OAG Lead/Lag Cash Working Capital Calculation - Virginia Regulatory Books
For the Test Year Ended 9/30/2016
Case No. PUE-2016-00143
Support for Column (3) of Schedule 22

Line No.		(1) Virginia Regulatory Books	(2) Average Daily Amount	(3) Expense (Lead)/Lag Days	(4) Revenue Lag	(5) Net (Lead)/Lag Days	(6) Working Capital (Provided)/ Required
	Operating Expenses						
1	Purchased Gas Expense	82,363,366	225,653	(31.3)	49.5	18.2	4,099,821
2	OPEB Expense	(382,550)	(1,048)	-	49.5	49.5	(51,849)
3	Pension Expense	2,191,373	6,004	-	49.5	49.5	297,007
4	Payroll Expense	18,248,462	49,996	(34.8)	49.5	14.7	734,563
5	Health Benefits Expense	1,775,239	4,864	(11.0)	49.5	38.5	187,170
6	Other Benefits Expense	89,619	246	(12.1)	49.5	37.3	9,165
7	Uncollectible Expense	749,732	2,054	(49.5)	49.5	0.0	-
8	401K Benefits Expense	869,316	2,382	(11.1)	49.5	38.4	91,402
9	Allocations From Services Company	18,846,106	51,633	(21.6)	49.5	27.9	1,439,117
10	Other O&M Expenses	18,550,097	50,822	(40.3)	49.5	9.2	465,646
11	Depreciation and Amortization Expense	31,051,316	85,072	-	49.5	49.5	4,208,525
12	Federal Income Taxes (Current)	(16,305,626)	(44,673)	(38.0)	49.5	11.5	(512,403)
13	Federal Income Taxes (Deferred)	35,557,064	97,417	-	49.5	49.5	4,819,209
14	State Income Tax (Current)	(976,478)	(2,675)	(38.0)	49.5	11.5	(30,686)
15	State Income Tax (Deferred)	3,462,590	9,487	-	49.5	49.5	469,301
16	Property Tax	7,430,588	20,358	(107.4)	49.5	(57.9)	(1,179,439)
17	Payroll Tax	997,646	2,733	(15.8)	49.5	33.7	92,136
18	AFUDC	-	-	(49.5)	49.5	0.0	-
19	Charitable Donations	-	-	(49.5)	49.5	0.0	-
20	Interest on Customer Deposits	52,598	144	(182.5)	49.5	(133.0)	(19,170)
21	Interest on Supplier Refunds	25,706	70	(182.5)	49.5	(133.0)	(9,369)
22	Other Expense/Income	1,214,404	3,327	(49.5)	49.5	0.0	-
23	LT Interest Expense	18,563,072	50,858	(45.8)	49.5	3.7	189,172
24	ST Interest Expense	-	-	-	49.5	49.5	-
25	JDC Expense	-	-	(49.5)	49.5	0.0	-
26	Income Available for Common Equity	19,575,489	53,631	(49.5)	49.5	0.0	-
27	**Totals**	**243,949,131**	**668,354**				**15,299,317**
	Plus:						
28	State Withholding Taxes	1,100,588	3,015	(14.7)	49.5	34.7	104,717
29	Federal Withholding Taxes	3,314,431	9,081	(14.7)	49.5	34.7	315,432
30	State Consumption Tax	2,498,746	6,846	(52.2)	49.5	(2.7)	(18,564)
31	Local Consumption Tax	661,660	1,813	(52.2)	49.5	(2.7)	(4,916)
32	Customer Utility Tax	11,409,037	31,258	(52.2)	49.5	(2.7)	(85,179)
33	Federal Excise Tax	-	-	(69.8)	49.5	(20.3)	-
34	Motor Fuel Tax	22,207	61	(65.1)	49.5	(15.6)	(949)
35	Sales and Use Tax	101,408	278	(32.1)	49.5	17.4	4,825
36	**Cash Working Capital (Lead/Lag)**						**15,614,683**
37	**BALANCE SHEET ITEMS (Schedule 28)**						18,822,424
38	**TOTAL CASH WORKING CAPITAL**						**34,437,107**

Virginia Natural Gas, Inc.
OAG Lead/Lag Cash Working Capital Calculation - Virginia Jurisdictional Cost of Service
For the Test Year Ended 9/30/2016
Case No. PUE-2016-00143
Support for Column (5) of Schedule 22

Line No.		(1) Virginia Regulatory Books	(2) Non-Jurisdictional Business	(3) Virginia Jurisdiction Cost of Service	(4) Average Daily Amount	(5) Expense (Lead)/Lag Days	(6) Revenue Lag	(7) Net (Lead)/Lag Days	(8) Working Capital (Provided)/ Required	(9) Non-Jurisdictional %
	Operating Expenses									
1	Purchased Gas Expense	82,363,368	11,827,379	70,535,986	193,249	(31.3)	49.5	18.2	3,511,087	14.36%
2	OPEB Expense	(382,550)	(32,134)	(350,416)	(960)	-	49.5	49.5	(47,493)	8.40%
3	Pension Expense	2,191,373	184,075	2,007,298	5,499	-	49.5	49.5	272,058	8.40%
4	Payroll Expense	18,248,462	1,532,871	16,715,591	45,796	(34.8)	49.5	14.7	672,859	8.40%
5	Health Benefits Expense	1,775,239	149,120	1,626,119	4,455	(11.0)	49.5	38.5	171,447	8.40%
6	Other Benefits Expense	89,619	7,528	82,091	225	(12.1)	49.5	37.3	8,395	8.40%
7	Uncollectible Expense	749,732	62,978	686,755	1,882	(49.5)	49.5	-	-	8.40%
8	401K Benefits Expense	869,316	73,023	796,293	2,182	(11.1)	49.5	38.4	83,724	8.40%
9	Allocations From Services Company	18,846,106	1,583,073	17,263,033	47,296	(21.6)	49.5	27.9	1,318,231	8.40%
10	Other O&M Expenses	18,550,097	(180,380)	18,730,477	51,316	(40.3)	49.5	9.2	470,174	8.40%
11	Depreciation and Amortization Expense	31,051,316	2,763,567	28,287,749	77,501	-	49.5	49.5	3,833,966	8.90%
12	Federal Income Taxes (Current)	(16,305,626)	(737,014)	(15,568,611)	(42,654)	(38.0)	49.5	11.5	(489,243)	4.52%
13	Federal Income Taxes (Deferred)	35,557,064	1,607,179	33,949,885	93,013	-	49.5	49.5	4,601,381	4.52%
14	State Income Tax (Current)	(976,478)	(44,137)	(932,341)	(2,554)	(38.0)	49.5	11.5	(29,299)	4.52%
15	State Income Tax (Deferred)	3,462,590	156,509	3,306,081	9,058	-	49.5	49.5	448,088	4.52%
16	Property Tax	7,430,588	594,447	6,836,141	18,729	(107.4)	49.5	(57.9)	(1,085,084)	8.00%
17	Payroll Tax	997,646	79,812	917,835	2,515	(15.8)	49.5	33.7	84,766	8.00%
18	AFUDC	-	-	-	-	(49.5)	49.5	-	-	0.00%
19	Charitable Donations	-	-	-	-	(49.5)	49.5	-	-	8.00%
20	Interest on Customer Deposits	52,598	6,725	45,873	126	(182.5)	49.5	(133.0)	(16,719)	12.79%
21	Interest on Supplier Refunds	25,706	3,287	22,420	61	(182.5)	49.5	(133.0)	(8,171)	12.79%
22	Other Expense/Income	1,214,404	1,214,404	-	-	(49.5)	49.5	-	-	100.00%
23	LT Interest Expense	18,563,072	1,639,119	16,923,953	46,367	(45.8)	49.5	3.7	172,468	8.83%
24	ST Interest Expense	-	-	-	-	-	49.5	49.5	-	
25	JDC Expense	-	-	-	-	(49.5)	49.5	-	-	
26	Income Available for Common Equity	19,575,489	2,729,929	16,845,560	46,152	(49.5)	49.5	-	-	
27	Totals	243,949,131	25,221,359	218,727,771	599,254				13,972,637	
	Plus:									
28	State Withholding Taxes	1,100,588	88,047	1,012,541	2,774	(14.7)	49.5	34.7	96,339	8.00%
29	Federal Withholding Taxes	3,314,431	265,154	3,049,276	8,354	(14.7)	49.5	34.7	290,197	8.00%
30	State Consumption Tax	2,498,746	199,900	2,298,846	6,298	(52.2)	49.5	(2.7)	(17,079)	8.00%
31	Local Consumption Tax	661,660	52,933	608,727	1,668	(52.2)	49.5	(2.7)	(4,523)	8.00%
32	Customer Utility Tax	11,409,037	912,723	10,496,314	28,757	(52.2)	49.5	(2.7)	(78,364)	8.00%
33	Federal Excise Tax	-	-	-	-	(69.8)	49.5	(20.3)	-	8.00%
34	Motor Fuel Tax	22,207	1,777	20,431	56	(65.1)	49.5	(15.6)	(873)	8.00%
35	Sales and Use Tax	101,408	8,113	93,295	256	(32.1)	49.5	17.4	4,439	8.00%
36	Cash Working Capital (Lead/Lag)								14,262,773	
37	BALANCE SHEET ITEMS (Schedule 28)								17,290,569	
38	TOTAL CASH WORKING CAPITAL								31,553,342	

Virginia Natural Gas, Inc.
OAG Lead/Lag Cash Working Capital Calculation - Virginia Jurisdictional Cost of Service After Ratemaking Adjustments
For the Rate Year Ended 8/31/2018
Case No. PUE-2016-00143
Support for Column (3) of Schedule 24

Line No.		(1) Virginia Jurisdiction Cost of Service	(2) Rate Making Adjustments	(3) VA Jurisdiction Cost of Service After Adjustments	(4) Average Daily Amount	(5) Expense (Lead)/Lag Days	(6) Revenue Lag	(7) Net (Lead)/Lag Days	(8) Working Capital (Provided)/ Required
	Operating Expenses								
1	Purchased Gas Expense	70,535,986	19,712,563	90,248,550	247,256	(31.3)	49.5	18.2	4,492,324
2	OPEB Expense	(350,416)	(148,283)	(498,699)	(1,366)	-	49.5	49.5	(67,591)
3	Pension Expense	2,007,298	1,171,222	3,178,520	8,708	-	49.5	49.5	430,799
4	Payroll Expense	16,715,591	1,056,587	17,772,178	48,691	(34.8)	49.5	14.7	715,390
5	Health Benefits Expense	1,626,119	793,712	2,419,831	6,630	(11.0)	49.5	38.5	255,131
6	Other Benefits Expense	82,091	(71,583)	10,508	29	(12.1)	49.5	37.3	1,075
7	Uncollectible Expense	686,755	59,180	745,934	2,044	(49.5)	49.5	-	-
8	401K Benefits Expense	796,293	64,448	860,742	2,358	(11.1)	49.5	38.4	90,500
9	Allocations From Services Company	17,263,033	(635,398)	16,627,635	45,555	(21.6)	49.5	27.9	1,269,711
10	Other O&M Expenses	18,730,477	(611,246)	18,119,231	49,642	(40.3)	49.5	9.2	454,830
11	Depreciation and Amortization Expense	28,287,749	5,480,313	33,768,061	92,515	-	49.5	49.5	4,576,738
12	Federal Income Taxes (Current)	(15,568,611)	9,615,459	(5,953,153)	(16,310)	(38.0)	49.5	11.5	(187,077)
13	Federal Income Taxes (Deferred)	33,949,885	(16,496,660)	17,453,225	47,817	-	49.5	49.5	2,365,515
14	State Income Tax (Current)	(932,341)	(153,340)	(1,085,681)	(2,974)	(38.0)	49.5	11.5	(34,117)
15	State Income Tax (Deferred)	3,306,081	(123,122)	3,182,959	8,720	-	49.5	49.5	431,401
16	Property Tax	6,836,141	934,168	7,770,309	21,289	(107.4)	49.5	(57.9)	(1,233,363)
17	Payroll Tax	917,835	58,706	976,541	2,675	(15.8)	49.5	33.7	90,187
18	AFUDC	-	-	-	-	(49.5)	49.5	-	-
19	Charitable Donations	-	-	-	-	(49.5)	49.5	-	-
20	Interest on Customer Deposits	45,873	3,827	49,701	136	(182.5)	49.5	(133.0)	(18,115)
21	Interest on Supplier Refunds	22,420	(13,129)	9,291	25	(182.5)	49.5	(133.0)	(3,386)
22	Other Expense/Income	-		-	-	(49.5)	49.5	-	-
23	LT Interest Expense	16,923,953	(3,837,231)	13,086,722	35,854	(45.8)	49.5	3.7	133,364
24	ST Interest Expense	-	702,008	702,008	1,923	-	49.5	49.5	95,146
25	JDC Expense	-	-	-	-	(49.5)	49.5	-	-
26	Income Available for Common Equity	16,845,560	3,155,744	20,001,305	54,798	(49.5)	49.5	-	-
27	**Totals**	**218,727,771**	**20,717,946**	**239,445,718**	**656,016**				**13,858,463**
	Plus:								
28	State Withholding Taxes	1,012,541		1,012,541	2,774	(14.7)	49.5	34.7	96,339
29	Federal Withholding Taxes	3,049,276		3,049,276	8,354	(14.7)	49.5	34.7	290,197
30	State Consumption Tax	2,298,846		2,298,846	6,298	(52.2)	49.5	(2.7)	(17,079)
31	Local Consumption Tax	608,727		608,727	1,668	(52.2)	49.5	(2.7)	(4,523)
32	Customer Utility Tax	10,496,314		10,496,314	28,757	(52.2)	49.5	(2.7)	(78,364)
33	Federal Excise Tax	-		-	-	(69.8)	49.5	(20.3)	-
34	Motor Fuel Tax	20,431		20,431	56	(65.1)	49.5	(15.6)	(873)
35	Sales and Use Tax	93,295		93,295	256	(32.1)	49.5	17.4	4,439
36	**Cash Working Capital (Lead/Lag)**								**14,148,599**
37	**BALANCE SHEET ITEMS (Schedule 28)**								17,290,569
38	**TOTAL CASH WORKING CAPITAL**								**31,439,168**

Virginia Natural Gas, Inc.
OAG Balance Sheet - Other Cash Working Capital
For the Test Year Ended 9/30/2016
Case No. PUE-2016-00143

Account	Description	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Average	Non-Jurisdictional Business	Jurisdictional Business	Non-Jurisdictional Percentage
Additional Uses/(Sources) of Cash Working Capital																		
100121	Utility Capital Payroll Accrued - Need to Reverse Sign (1)	(99,154)	(185,579)	(181,399)	(34,714)	(64,291)	(93,490)	(133,358)	(146,504)	(162,867)	(49,717)	(56,378)	(111,313)	(118,034)	(111,292)	(9,349)	(101,943)	8.40%
161400	VNG Pre-94 Regulatory Asset Amortization	5,582,850	5,555,880	5,528,910	5,501,940	5,474,970	5,448,000	5,421,030	5,394,060	5,367,090	5,340,120	5,313,150	5,286,180	5,259,210	5,421,030	456,077	4,962,953	8.45%
162150	Other Long-Term Assets	388,033	379,379	370,725	362,071	353,417	344,763	336,109	327,455	318,801	310,147	301,493	292,839	284,185	336,109	29,678	306,431	8.83%
162450	ATPI Capitalized Clearing	(2)	-	-	-	-	-	-	-	-	-	-	-	-	(0)	-	(0)	8.40%
164100	Net Pension Asset	6,971	7,746	8,520	96,721	97,614	98,507	99,399	100,292	101,185	102,536	103,505	-	-	63,307	5,349	57,958	8.45%
220004	Accrued Vacation Payable	-	-	-	(18,943)	(12,629)	(8,314)	-	-	(10,944)	(10,944)	(10,944)	(10,944)	(10,944)	(7,124)	(598)	(6,526)	8.40%
225105	A/P - Inventory	(8,795)	(5,644)	(5,644)	(5,838)	(5,575)	(5,644)	(3,675)	(5,644)	(5,644)	(5,644)	(9,087)	(5,644)	(5,644)	(5,840)	(532)	(5,308)	9.11%
225151	Unclaimed Customer Credits & Checks	(917,856)	(854,672)	(872,760)	(891,225)	(908,497)	(927,711)	(946,333)	(953,771)	(970,401)	(974,971)	(982,139)	(993,142)	(993,701)	(937,479)	(110,904)	(817,575)	12.79%
225500	Payroll Deductions	-	-	-	41,076	(177)	-	(483)	40,923	40,923	-	-	149,655	-	20,917	1,757	19,160	8.40%
225507	One Pledge Club Atlanta	(10,027)	(2,885)	(5,790)	(8,715)	(3,158)	(6,906)	(8,746)	(2,753)	(5,480)	(9,560)	(3,919)	(6,361)	(8,606)	(6,304)	(530)	(5,774)	8.40%
225512	Employee Stock Purchase Plan	(18,260)	(36,420)	(54,630)	(23,170)	(41,070)	(58,795)	(18,600)	(37,200)	(55,300)	-	-	-	-	(26,419)	(2,227)	(24,192)	8.43%
225521	P.A.C Payable	-	-	-	-	-	-	(35)	-	-	(100)	(123)	(50)	-	(24)	(2)	(22)	8.40%
225522	H.E.A.T Payments	(7,980)	(9,127)	(7,254)	(7,007)	(5,121)	(4,974)	(4,208)	(4,452)	(6,714)	(8,651)	(7,874)	(8,830)	(8,850)	(6,757)	-	(6,757)	0.00%
225526	Employee Court Orders	-	-	(840)	(1,152)	-	-	-	-	-	(163)	(163)	(163)	(163)	(203)	(17)	(186)	8.40%
225541	HSA Employee Contributions	(3,935)	(3,935)	-	-	-	6,031	-	-	-	(2,839)	(2,839)	(2,883)	-	(800)	(68)	(732)	8.45%
225542	Met Life Deduction	(365)	(23)	7	30	426	30	30	30	30	(441)	30	30	30	(12)	(1)	(11)	8.45%
225548	AFLAC Supplemental Insurance	(185)	(1,202)	(185)	(185)	40	(202)	(202)	(202)	(202)	-	-	-	-	(194)	(16)	(178)	8.45%
225560	Union Dues VNG Local 50	-	-	-	-	-	-	-	-	-	(4,783)	(9,566)	-	-	(1,104)	(93)	(1,011)	8.40%
245600	Escheat - Deposit Balance 2001	(1,500)	(1,500)	(1,500)	(1,500)	(1,500)	(1,500)	(1,500)	(1,500)	(1,500)	(1,500)	(1,500)	(1,500)	(1,500)	(1,500)	(192)	(1,308)	12.79%
247020	Non-Qualified/Excess Benefit Plan	(4,249)	(4,721)	(5,193)	(69,402)	(69,890)	(70,378)	(70,866)	(71,354)	(71,842)	(74,872)	(75,784)	(180,765)	(181,790)	(73,162)	(6,182)	(66,980)	8.45%
247030	Pension Liability/Qualified Plan	(22,099,450)	(22,153,392)	(22,207,334)	(22,177,730)	(22,178,597)	(22,179,463)	(22,180,329)	(22,181,195)	(22,182,061)	(22,256,844)	(22,270,030)	(34,177,912)	(15,240,354)	(22,575,745)	(1,903,135)	(20,672,610)	8.43%
248800	Other Postretirement Benefits	8,338,721	8,420,486	8,501,350	7,975,504	8,163,942	8,255,878	8,373,958	8,444,944	8,540,840	8,724,163	8,849,897	9,499,087	9,589,023	8,590,676	725,912	7,864,764	8.45%
258899	Misc/Other Deferred Credits	(169,944)	(168,540)	(167,135)	(165,731)	(164,326)	(162,922)	(161,517)	(160,113)	(158,708)	(157,304)	(155,899)	(154,495)	(153,090)	(161,517)	(14,343)	(147,174)	8.88%
277060	Pension Current Liability - Excess	-	-	-	(2,114)	(2,114)	(2,114)	(2,114)	(2,114)	(2,114)	(2,114)	(2,114)	(4,446)	(4,446)	(1,985)	(167)	(1,818)	8.43%
278500	Reserve for Health Insurance	(57,771)	(57,771)	(57,771)	(66,650)	(66,650)	(66,650)	(66,650)	(66,650)	(66,650)	(66,650)	(66,650)	(66,650)	(66,650)	(64,601)	(5,737)	(58,864)	8.88%
202010	Actuarial (gain)/loss	31,279,523	31,279,523	31,279,523	31,945,942	29,507,227	29,507,227	29,507,227	29,507,227	29,507,227	29,507,227	29,507,227	41,127,969	41,127,969	31,891,619	2,688,463	29,203,156	8.43%
202012	Reclass actuarial G/(L) to Net	(1,829,036)	(2,032,263)	(2,235,489)	(2,438,715)	(156,097)	(312,194)	(468,290)	(624,387)	(780,484)	(1,003,274)	(1,170,488)	(1,527,826)	(1,790,253)	(1,259,146)	(106,146)	(1,153,000)	8.43%
202014	Prior Service Costs	(702,396)	(702,395)	(702,395)	(702,756)	(473,333)	(473,333)	(473,333)	(473,333)	(473,333)	(473,333)	(473,333)	(477,176)	(477,176)	(544,433)	(45,896)	(498,537)	8.43%
202016	R/C Prior Service Costs to NI	172,087	191,186	210,304	229,423	21,431	42,861	64,292	85,722	107,153	128,937	150,427	171,922	193,415	136,068	11,472	124,616	8.43%
	A/P CWIP (2)	(848,716)	(768,415)	(1,404,389)	(3,725,761)	(456,577)	(918,922)	(2,051,724)	(851,238)	(1,557,781)	(459,358)	(1,203,197)	(318,184)	(160,925)	(1,132,707)	(109,873)	(1,022,834)	9.70%
	Reserve for Injuries and Damages (3)	(629,199)	(823,352)	(728,186)	(728,186)	(738,110)	(738,110)	(738,110)	(738,874)	(738,874)	(738,874)	(737,597)	(737,597)	(737,597)	(718,974)	(63,845)	(655,129)	8.88%
Total Net Uses/(Sources) of Average Cash Working Capital		18,382,345	18,222,384	17,261,456	15,083,414	18,273,356	17,878,817	16,473,971	17,579,371	18,733,285	17,813,196	16,976,109	17,741,703	36,494,308	18,822,424	1,531,855	17,290,569	8.14%

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Schedule GAW-5

Comparison of VNG Property Records Footage By Size and Type to Mr. Heintz's Minimum-System Analysis

VNG

Comparison of VNG Property Records Footage by Size and Type

To Mr. Heintz's Minimum-System Analysis

Plastic Mains

		Installed Footage	
NOMINAL DIAMETER	MATERIAL	Heintz Analysis 1/	Actual Property Records 2/
0.5	All Plastic	228	3,030
0.75	All Plastic	1,954	418,086
1	All Plastic	7	0
1.25	All Plastic	14,875	70,856
1.375	All Plastic	558	0
2	All Plastic	668,926	4,542,730
2.5	All Plastic	50	0
2.625	All Plastic	10,704	0
3	All Plastic	495	841
4	All Plastic	22,366	762,153
6	All Plastic	2,397,029	167,467
8	All Plastic	2,308,351	157,866
Unknown	All Plastic		10,916,177
Total		5,425,543	17,039,206

Steel Mains

		Installed Footage	
NOMINAL DIAMETER	MATERIAL	Heintz Analysis 1/	Actual Property Records 2/
0.5	Steel	115	18
0.75	Steel	6,516	56
1	Steel	661	0
1.25	Steel	106,825	0
1.5	Steel	11,520	0
2	Steel	4,615,020	2,791
2.5	Steel	7,406	0
3	Steel	20,985	44
3.5	Steel	15	0
4	Steel	1,083,826	6,516
5	Steel	75	0
6	Steel	1,056,007	34,592
8	Steel	1,209,940	118,375
10	Steel	4,695	0
12	Steel	602,447	224,939
14	Steel	7,209	1
16	Steel	543,292	28,187
18	Steel	145,804	1,468
20	Steel	123,584	76,621
24	Steel	533,740	6
Unknown			9,753,144
Total		10,079,682	10,246,758

VNG
Comparison of VNG Property Records Footage by Size and Type
To Mr. Heintz's Minimum-System Analysis

Mains (Other)

		Installed Footage	
NOMINAL DIAMETER	**MATERIAL**	**Heintz Analysis 1/**	**Actual Property Records 2/**
1.25	Brass	2	
1	Cast Iron	722	
1.25	Cast Iron	68	
2	Cast Iron	16,669	
3	Cast Iron	1,159	
4	Cast Iron	47,619	
6	Cast Iron	8,281	
8	Cast Iron	1,665	
10	Cast Iron	1,692	
0.625	Copper	84	
0.75	Copper	1	
0.875	Copper	2,514	
1.25	Copper	11	12
1.375	Copper	41,719	
2.125	Copper	7,586	
2.5	Copper	0	19
2.625	Copper	6,989	
1.25	Inner-Tight	2,072	
1.5	Inner-Tight	197	
2	Inner-Tight	27,355	
3	Inner-Tight	2,530	
4	Inner-Tight	3,498	
6	Inner-Tight	17,366	
8	Inner-Tight	858	
2	UNK	5,679	
2	Wrought Iron	4,483	
4	Wrought Iron	2,295	
Unknown	Iron		695,489
Unknown	Copper		8,661
Unknown	Unknown		1,995,076
Total		203,114	2,699,257

1/ Per Staff 1-2(d) and OAG 3-40(a).
2/ Per OAG 2-41.

Schedule GAW-6

OAG
Customer Cost Analysis

VIRGINIA NATURAL GAS
Residential Customer Cost Analysis

	VNG Peak & Average Study	
	ROE @ 9.50%	ROE @ 10.25%
Gross Plant		
Services	$252,776,986	$252,776,986
Meters	$39,334,556	$39,334,556
Meter Installations	$13,416,454	$13,416,454
House Regulators	$8,854,366	$8,854,366
House Regulators Installations	$3,709,476	$3,709,476
Total Gross Plant	**$318,091,838**	**$318,091,838**
CWIP		
Services	$3,880,096	$3,880,096
Meters	$677,161	$677,161
Meter Installations	$0	$0
House Regulators	$61,068	$61,068
House Regulators Installations	$0	$0
Total CWIP	**$4,618,325**	**$4,618,325**
Depreciation Reserve 1/		
Services	$105,221,279	$105,221,279
Meters	$14,575,988	$14,575,988
Meter Installations	$7,032,814	$7,032,814
House Regulators	$3,426,770	$3,426,770
House Regulators Installations	$2,203,595	$2,203,595
Total Depreciation Reserve	**$132,460,446**	**$132,460,446**
Total Net Plant	$190,249,717	$190,249,717
Total Rate Base	**$190,249,717**	**$190,249,717**
Operation & Matinenance Expenses		
Oper Meter & House Reg	$815,831	$815,831
Customer Installations Expense	$1,291,714	$1,291,714
Maint Services	$1,973,445	$1,973,445
Maint Meter & House Reg	$1,298,604	$1,298,604
Meter Reading	$347,906	$347,906
Customer Records & Collections	$5,157	$5,157
Total O&M Expenses	**$5,732,657**	**$5,732,657**
Depreciation Expense 2/		
Services	$7,456,921	$7,456,921
Meters	$2,103,190	$2,103,190
Meter Installations	$349,533	$349,533
House Regulators	$199,459	$199,459
House Regulators Installations	$90,661	$90,661
Total Depreciation Expense	**$10,199,764**	**$10,199,764**
Revenue Requirement		
Interest	$4,206,376	$4,206,376
Equity Return	$8,814,555	$9,510,441
Income Tax	$5,611,346	$6,054,347
Total	**$18,632,276**	**$19,771,163**
Revenue For Return	$18,632,276	$19,771,163
O&M Expenses	$5,732,657	$5,732,657
Depreciation Expense	$10,199,764	$10,199,764
Total Customer Revenue Requirement	$34,564,697	$35,703,584
Number of Bills	3,294,053	3,294,053
Monthly Cost	**$10.49**	**$10.84**

1/ Calculated per Spanos' Depreciation Study, Exhibit JJS-2, VII-6 utilizing the ratio of total Company depreciation reserve to gross plant multiplied by Residential gross plant above.

2/ Calculated per Spanos' Depreciation Study, Exhibit JJS-2, VII-6 utilizing the ratio of total Company depreciation accrual to gross plant multiplied by Residential gross plant above.